Electric Power System Cost/Loss Optimization Using Dynamic Thermal Rating and Linear Programming

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***Abstract*—Electric power systems consist of generation, transmission, and distribution components. As the demand for electricity grows seemingly endless, it is expected that a number of constraints, such as environmental, regulatory and economic, prevent the construction of new power plants and transmission lines. Finding improved ways to utilize the capacity supplied by existing power generation facilities and power transmission infrastructure is the problem that engineers, equipment manufacturers, and regulatory agencies are now facing.**

This paper introduces an optimization method using Dynamical Thermal Rating (DTR) and linear programming (LP) to minimize generation costs or transmission losses. DTR values are derived from a spatially resolved thermal model of the transmission system based on actual weather conditions along the line. This allows determination of line ampacity based on thermal bottlenecks that can exist at different locations along the line. The thermal model can also account for power losses more accurately, by considering actual distribution of temperature-dependent conductor resistance along the line.

The model is used in a case study involving a simplified power transmission system with two types of generators, and a single load center. The simulation results show that more energy from hydro power plant can be transmitted to the load center, instead of using more expensive and polluting thermal generation.

***Index Terms*—Loss/Cost Optimization, Dynamic Thermal Rating, Electrothermal Coordination, Power Generation Dispatch, Linear Programming**

I. Introduction

As the demand for electricity grows seemingly endless, it is expected that a number of constraints, such as environmental, social, regulatory and economic, prevent the construction of new power plants and transmission lines [1]. Finding improved ways to utilize the capacity supplied by existing power generation facilities and power transmission infrastructure is the problem that engineers, equipment manufacturers, and regulatory agencies are now facing.

From the generation perspective, different types of technologies can be used, each with specific costs and benefits. The major differences include capital and operation costs, performance characteristics, and environmental impact. The ideal generation scenario would involve using the technologies with the least costs and minimum impact. However, this is not always possible, as the type of generation strongly depends on local conditions, e.g. availability of running water or reservoir for a hydro plant. Although energy can be generated at a distant location and transmitted to the load center, long distance transmission is associated with higher power losses, and thus increases the final cost of energy. In order to maximize the usage of existing transmission and generation assets, all these aspects must be considered under a selected optimization criteria.

This paper describes an optimization approach based on linear programming (LP). In addition to considering standard costs of generation using different technologies, the proposed approach incorporates other important constraints, such as ramp up and ramp down costs of thermal generation plants. Most importantly, the model uses spatially resolved, high-resolution thermal model of the transmission system to dynamically determine thermal limits and temperature-dependent losses of the system. This allows identification of transmission bottlenecks and spatial variability of losses in the system.

The performance of the optimization system is demonstrated using a case study involving a thermal plant adjacent to the load center, and a remote hydro generation station. The simulation results show a modest decrease in generation costs or system losses, depending on the criteria used. Further analysis shows that much greater improvements could be achieved if the load limitation, imposed by statically rated transmission system, were relaxed.

This paper is organized in five sections. Section II presents necessary background information, including dynamic thermal rating, basic principles of power generation dispatch, and cost models. The proposed optimization model is described in detail in Section III. The transmission network used as a case study is described in Section IV, along with simulation results using cost and losses as the optimization criteria. Finally, Section V brings major conclusions and outlines possible direction for future work.

II. Background

Electric power systems are comprised of sources of the electric energy (generators), energy delivery systems (transmission and distribution systems), and devices that use the energy (loads centers). In order to optimize the operation of these systems under the stochastic electricity demand, the subsystems must be described by a number of characteristics related to their performance, operation, and state. The following text briefly describes the three important characteristics considered in this study, and provides a concise review of relevant literature.

A. Economic Dispatch

In deregulated power industry, the problem of *economic dispatch* (ED) has become a crucial task in the operation and planning of power systems. Its main purpose is to schedule the committed generating units in such a way that required demand at load centers is met, at minimum cost, and while satisfying all operational constraints [2]. In other words, the generation of each individual

This work has been supported by the Natural Sciences and Engineering Research Council of Canada (NSERC), Newfoundland and Labrador Hydro (NLH), and partly supported by the Grant Agency of the Academy of Sciences of the Czech Republic No. M100300904.

unit is scheduled so that the costs of generation in the overall system is minimized [3]. Methods used to solve the ED problem range from linear programming [4] to heuristic approaches, such as particle swarm optimization [2]. Garver et al. at [4] used linear programming to determine the capacity shortages of transmission systems, and to aid system expansion studies to eliminate them. Generation fuel cost accuracy has a significant impact on efficiency of generation dispatch algorithm. Inverse incremental cost functions has been used in [5] to simplify the generation dispatch problem to a normal optimization problem.

B. Power Generation Costs

Operation of a power plant is associated with costs of several types. *Capital cost* can be defined as the expenses for design, planning, and installation of a generator, along with associated land, buildings, and equipment. This cost is considered before building the generator, and amortized over its lifespan. *Operation and management cost* can be further divided into two components: variable and fixed. The *variable cost* is the sum of cost of fuel, added to handling, transportation, and storage charges. This cost is a function of the actual amount of generation. The *fixed cost* is the result of plant maintenance. Hence, this cost exists regardless of the amount of generation, provided that the generator is continuously in operational or stand-by state. It is usually expressed as a monthly cost, normalized to the amount of generation capacity, not actual energy production. A thorough explanation of these costs for different types of generators can be found, e.g., in [6] and [7].

Some types of generation, such as thermal power plants, also have so called *start-up costs*. They are only incurred during the transition of the generator from "off" to "on" state. This cost can be described using exponential function [8] of the unit's off-time duration

$$CS_i\left(X_i^{\text{off}}(t)\right) = \alpha_i + \beta_i \left[1 - e^{\frac{-X_i^{\text{off}}(t)}{\tau_i}}\right], \qquad (1)$$

where τ_i is the time constant of i-th generator start-up function, X_i^{off} is the time duration for which unit i has been off before restarting, and α_i and β_i are generator specific constants. Because of the physical characteristics of thermal plant units, their generation increase and decrease rates are limited by parameter called ramp-up, RU_i, and ramp-down, RD_i. Defined only for thermal plants, such as gas, coal, oil, etc [9], these parameters assume values depending on the capacity of particular generator i.

C. Conductor's Thermal Limit and Dynamic Thermal Rating

The thermal limit of transmission line is established so that the circuit is not thermally overloaded, and clearance requirements between the line and objects beneath are met [10]. Traditionally, thermal limits have been determined using a set of conservative weather conditions and an assumed maximum acceptable conductor temperature [11]. Usually expressed in terms of ampacity (i.e. the maximum allowable current to keep conductor temperature within acceptable range), the thermal limit obtained this way is called Static Thermal Rating (STR). Due to operating practices driven by safety and reliability requirements, the assumptions used to derive STR are very conservative. As a result, transmission systems using STR are greatly underutilized. At the same time, the risk of circuit failure is not completely eliminated, because the assumptions, while conservative, do not represent a true worst-case scenario.

To overcome these problems, Dynamic Thermal Rating (DTR) methods use direct, real-time measurements of conductor temperature or sag, or real-time estimates of the temperature using actual, rather than assumed, weather conditions. First envisioned in late 1970s [12], this approach has been further studied by number of authors, e.g. [13], [14], and commercially implemented. Although conventional DTR provides a number of advantages compared to STR, it may not capture the lowest value of ampacity which can vary significantly along the line [15]. To avoid this risk, a spatially-resolved thermal model of transmission system has been proposed [16]. In addition to the ability to determine ampacity based on the true bottleneck of the system, this model allows detailed examination of temperature-dependent power losses - a consideration important for ED modeling.

DTR has been considered in a number of studies dealing with optimization of electric power systems. A practical case study using DTR and favourable weather conditions to increase the ampacity of Idaho regional transmission system is described in [17]. The results demonstrate significant gain in total transmitted power. Adapa et al. [18] compare different aspects of using DTR, including it's effects on different parts of transmission systems. An application of conventional DTR to problem of electrothermal coordination is presented in [19]. Further applications of DTR include augmenting power transfer capability, network congestion management, etc. [20].

III. Optimization Method

This paper addresses the ED problem by optimizing power system for minimum generation cost or minimum losses. To demonstrate the value of DTR in comparison to STR, both rating approaches are applied in two separate simulations. An important distinction of the approach used here is the use of network thermal model with high spatial resolution. The power flow in the transmission network is optimized using *minimum cost flow network* [21].

A. Nomenclature

Variables and parameters used to define the network model and constraints are defined as follows

$D_{i,j}$	Length of line between busses i and j [km]
Z	Total (generation cost/transmission losses) of the whole system
N	Number of busses in the network
L	Power loss of the whole network [MW]
$L_{i,j}(t)$	Power loss of the line between busses i and j at time t [MW]
$PG(t)$	Total power generated at time t [MW]
$PG_i(t)$	Power generation at bus i at time t [MW]
$PG_i^{\max}(t)$	Max allowed generation at bus i at time t [MW]
$PG_i^{\min}(t)$	Min allowed generation at bus i at time t [MW]
$PF_{i,j}(t)$	Power flow through the line between busses i and j at time t [MW]
$PD_i(t)$	Power demand at bus i at time t [MW]
$I_{i,j}(t)$	Current flowing through the line between busses i and j at time t [A]
$C(t)$	Total cost of the power generation in network at time t [\$]
CF_i	Fixed costs of generating power with generator located at bus i [\$/min]
CV_i	Variable costs of generating power with generator located at bus i [\$/MW]

Δt — Simulation time step length [min]
RU_i,RD_i — Ramp-up/down limit of generator located at bus i [MW/h]
$A_{i,j}(t)$ — Ampacity of the line between busses i and j at time t [A]
$R_{i,j}(t)$ — Unit resistance of the line between busses i and j at time t [Ω/km]
$PH_{i,j}$ — Binary variable indicating connection between busses i and j
M — A large number used in the LP Model

B. Linear Programming Model

The optimization goal, either minimization of generation cost or minimization of power losses, is determined by an objective function. For cost minimization, the objective function has the following form

$$Z(t) = \min_{PF_{\cdot,\cdot}(t)} \sum_{i=1}^{N} \left[CF_i \times \Delta t + CV_i \times PG_i(t) \right]. \tag{2}$$

while loss minimization is driven by the following objective function

$$Z(t) = \min_{PF_{\cdot,\cdot}(t)} \sum_{i=1}^{N} \sum_{j=1}^{N} L_{i,j}(t) \tag{3}$$

Network restrictions, physical laws, and regulations are described by a number of constraints expressed by equations (4–11). The minimum and maximum generation limit for each unit at time step t are defined as follows

$$PG_i^{min}(t) \leq PG_i(t) \leq PG_i^{max}(t) \quad \forall i \in N \tag{4}$$

This constraint ensures that each generator is working within expected operating range. The lower limit may include a spinning reserve used to make sure that there is sufficient standby power to cope with forced or planned outages [22]. Generation/demand balance is guaranteed by the following equality

$$\sum_{i=1}^{N} PG_i(t) = \sum_{i=1}^{N} PD_i(t) + \sum_{i=1}^{N} \sum_{j=1}^{N} L_{i,j}(t). \tag{5}$$

i.e. the generated power is equal to the demand plus the losses in the network. The amount of losses in a transmission line is a function of the current flowing through the line, its unit resistance, and length

$$L_{i,j}(t) = D_{i,j} \times R_{i,j}(t) \times I_{i,j}^2(t) \quad \forall (i,j) \in (N,N). \tag{6}$$

This is a nonlinear constraint that must be linearized (e.g. piecewise) in order to use LP solver.

The following constraint ensures that at time step t, the sum of generated and incoming power (without losses) at node i is equal to the sum of power that is consumed at this node and all power flow that is leaving the node

$$PG_i(t) + \sum_{j=1}^{N} PF_{j,i}(t) - \sum_{j=1}^{N} L_{j,i}(t) = \\ = PD_i(t) + \sum_{j=1}^{N} PF_{i,j}(t); \quad \forall i \in N. \tag{7}$$

Structure of the network is described by binary variables PH. Value $PH_{i,j} = 1$ is assumed only when there is a physical line between busses i and j; otherwise $PH_{i,j} = 0$. This ensures that power flows only through existing lines

$$PF_{i,j}(t) \leq M \times PH_{i,j}; \quad \forall (i,j) \in (N,N) \tag{8}$$

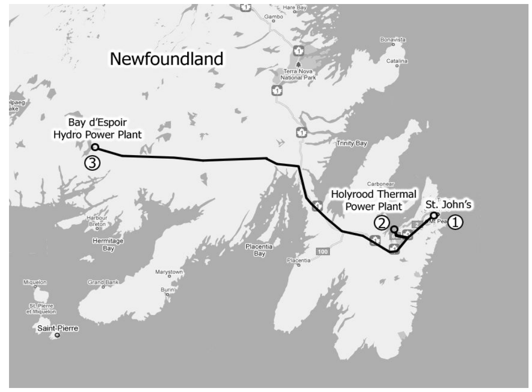

Fig. 1. Simplified transmission network

The following inequality ensures that the current flowing through a line does not exceed its ampacity (determined using STR or DTR)

$$I_{i,j}(t) \leq A_{i,j}(t); \quad \forall (i,j) \in (N,N) \tag{9}$$

Finally, the ramp-up and ramp-down limits of a generator are enforced as follows

$$PG_i(t) - PG_i(t-1) \leq RU_i; \quad \forall i \in N. \tag{10}$$

$$RD_i \leq PG_i(t-1) - PG_i(t); \quad \forall i \in N. \tag{11}$$

These constraints are applied only to thermal power plants. To keep the constraints uniform, variables RU_i and RD_i are also used for hydro or other types of generators without ramp-up/down limitation. However, they are assigned very large values, e.g. two times the maximum capacity of the generator.

The described model can be solved using a suitable LP package [23]. Use of the model is demonstrated using a case study described in the following section.

IV. Case Study

To demonstrate the operation of the method, and to illustrate the benefits of using DTR to solve the ED problem, the proposed system has been applied to a simplified power transmission network connecting two generators and one load center in Newfoundland, Canada. The load center is the city of St. John's, the greatest demand node on this island, with limited power generation facilities in its close proximity. Holyrood (oil) thermal power plant, located about 28 km from the city, covers only a portion of the demand, and produces power that is non-renewable and very expensive. To satisfy the full demand, remaining energy must be

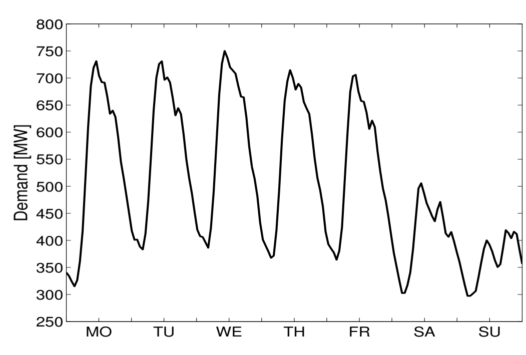

Fig. 2. Assumed weekly load profile of St. John's

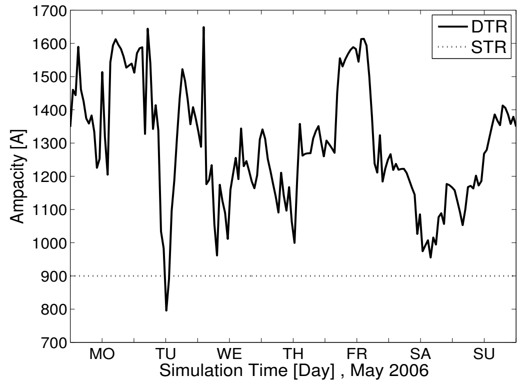

Fig. 3. Bay d'Espoir to St.John's transmission line ampacity calculated using static (STR) and dynamic (DTR) thermal rating methods

transmitted from hydro power plants located hundreds of kilometers west of the city.

A. Transmission Network

Simplified power transmission network used in the case study is illustrated on Fig.1. The network consists of three main busses, two power plants (Holyrood and Bay d'Espoir) and one demand node (city of St. John's). A detailed specification of each bus is provided in Table I.

TABLE I
GENERATION/DEMAND SPECIFICATIONS OF THE CASE STUDY

Bus Name	Bus #	Max. Gen. [MW]	Max. Load [MW]	Weekly Energy Demand [GWh]
St. John's	1	0	750	81.34
Holyrood	2	480	0	0
Bay d'Espoir	3	898	0	0

There are four major hydro power plants (Cat Arm, Hinds Lake, Upper Salmon, and Bay d'Espoir) in the central and north-west part of Newfoundland [24]. For simplicity, it is assumed that the total generation capacity of all four hydro stations is produced by Bay d'Espoir plant, located about 265 km east of the load center. This is the largest hydro power plant on the island, it generates 68% of the total hydroelectric capacity, and all other hydropower from the west part of the island is transmitted through this node.

The assumed characteristics and cost parameters of the two generators are summarized in Table II. More information about generator characteristics and costs can be found in [6], [9], [24], [25].

TABLE II
ASSUMED GENERATOR CHARACTERISTICS AND COST PARAMETERS IN CASE STUDY

Generator Name	Bay d'Espoir	Holyrood
Generation Capacity [MW]	898	480
Spinning Reserve [MW]	150	150
Generator type	Hydro	Thermal
Ramp Up Coef. [MW/h]	-	110
Ramp Down Coef. [MW/h]	-	160
Fixed Cost [k$/month]	4490	1836
Variable Cost [k$/MW]	-	0.13

Three main power transmission lines are considered in the case study. First line No. 31 draws from Bay d'Espoir directly to St. John's, second line No. 32 begins also in Bay d'Espoir and it extends 260 km to Holyrood. The third line No. 21 continues from Holyrood to St. John's. Table III provides the assumed characteristics of the conductors' along with their static thermal rating, which can be found in [26]. All power lines are almost parallel and they pass through one power transmission corridor.

TABLE III
ASSUMED TRANSMISSION LINE CHARACTERISTICS IN CASE STUDY

Line No.	Line Start	Line End	Cond. Type	Static Rating [A]	Line Length [km]
31	Bay d'Espoir	St. John's	Drake	900	265
32	Bay d'Espoir	Holyrood	Drake	900	260
21	Holyrood	St. John's	Plover	1275	28

The last part of transmission network is the demand node at St. John's. Fig.2 shows sample weekly load profile, derived from normalized load profile provided in [27]. Assumed maximum load during peak hours is 750MW and corresponds to total weekly energy consumption of almost 85GWh.

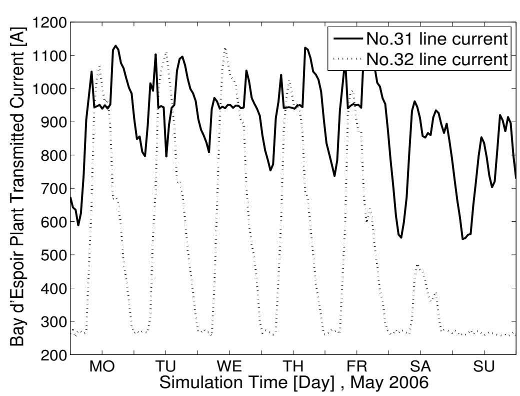

Fig. 4. Line currents for cost optimization with DTR

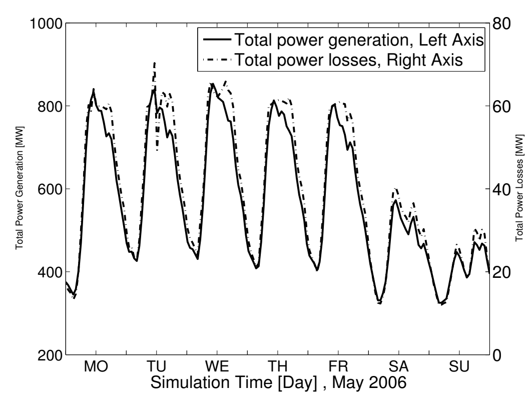

Fig. 5. Total generated power vs losses

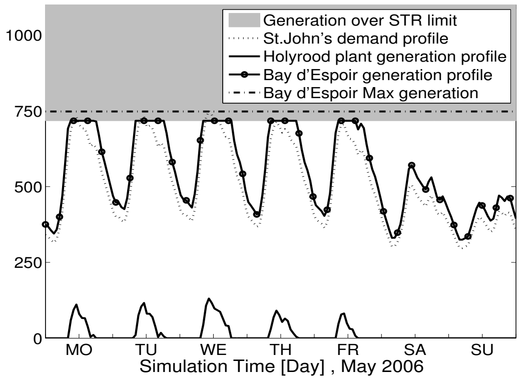

Fig. 6. Hydro and thermal power generation for cost optimization with STR

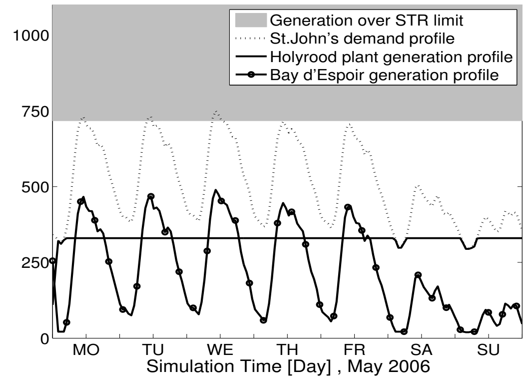

Fig. 8. Hydro and thermal power generation for loss optimization with STR

B. Local Weather Information

In order to calculate ampacities corresponding to DTR, actual weather conditions along the transmission corridors must be considered. Weather information used in this study was derived from the North American Regional Reanalysis (NARR) historical dataset [28]. One week (1st May 2006 – 7th May 2006) worth of NARR data was interpolated to the power transmission corridor, with 1-hour time resolution. Meteorological variables used for calculation the DTR conductor ampacity include horizontal wind speed and direction, ambient temperature, and short/long-wave radiation [29]. Local ampacity was determined this way at multiple locations along the lines, and the minimal value for a particular line was considered as the limiting factor. Figure 3 illustrates comparison of static (STR) and dynamic (DTR) ampacities for power transmission line No. 31. During the one week period considered in this study, dynamic ampacity was consistently greater than static ampacity. The mean value of dynamic ampacity was 1290A and standard deviation 180A.

C. Simulation Results

LP model for cost optimization was considered first. Results show that large amount of less expensive power could be transmitted from hydro power plant to city of St. John's. Holyrood thermal plant covers only peak demand, which is non-transferable due to line ampacities. Significant differences between system with STR and DTR can be observed. The use of DTR cuts total generation cost by almost 122.000$ (7%), while increases losses only by less than 1%.

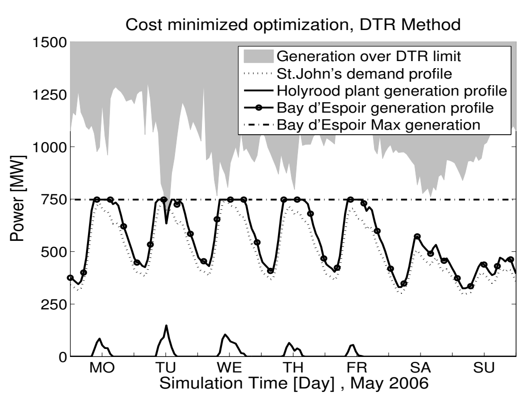

Fig. 7. Hydro and thermal power generation for cost optimization with DTR

Fig. 4 provides the profile of current flowing through transmission lines No. 31 and No. 32 (both begin at Bay d'Espoir generator). Total power generation and losses in the network are shown in Figure 5. Comparisons of hydro and thermal power generation in a system using STR and DTR are shown in Fig. 6 and Fig. 7 respectively. In both cases, the thermal plant covers peak demand. However, network using DTR provides a significant decrease in thermal power generation.

Results of loss minimization show about 5.1 GWh decrease in the amount of losses for both networks (STR and DTR) compared to the losses resulting from generation cost minimization. This is the effect of using the maximum capacity of the thermal plant, as shown in Fig. 8. This prevents larger losses caused by transmitting hydro power over much longer transmission lines. However, the improved efficiency of the system diminishes in the light of a huge increase of the total cost of power generation (up to 507% with DTR, and 473% with STR). This is caused by the extensive use of thermal power that is considerably more expensive compared to hydro. In addition, the loss-optimal configurations of the network would significantly contribute to emissions of greenhouse gases.

TABLE IV
SIMULATION RESULTS

Cost Minimization	DTR Method	STR method
generated energy[GWh]	95.864	95.471
generation cost [k$]	1693.6	1815.6
losses [GWh]	6.6495	6.2567
losses/generation percent	6.85%	6.03%
Loss Minimization	DTR Method	STR method
generated energy[GWh]	90.736	90.743
generation cost [k$]	8588.0	8584.1
losses [GWh]	1.5210	1.5287
losses/generation percent	1.68%	1.42%

Table IV shows the summary of all results. The first part of the table describes minimal cost optimization results of systems with STR and DTR. Results of loss minimization are summarized in the second part of the table; they show that DTR method involves cost optimization more than minimization of power losses and it cuts down costs of power generation significantly. DTR can provide also important information about remaining available transfer capacity, which can be used in system operations and planning.

V. Conclusions

This paper describes an approach to optimization of power generation cost/transmission losses based on DTR of power transmission system. Results obtained from a simulation of a simplified electric power network clearly show the value of DTR for economic operation of the entire system. As dynamically determined ampacities are usually larger than static ratings, systems using DTR can transmit more power under most circumstances. This allows better utilization of remote generation facilities that may provide power at lower costs compared to local generation. A typical example of such configuration is a thermal plan located in the vicinity of a load center, and a hydro plant located at much greater distance.

Future work will further refine the current LP model by adding generator start up costs, and possibly other constraints. The reactive power considerations, which are not implemented in the current study, will be added to the model as well.

Acknowledgments

The authors would like to thank Dr. Raymond Patterson at University of Alberta, School of Business, for his help regarding the definition of the LP model.

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