pense of the contract load. Clearly, greater willingness to pay is purchasing more dispatch right during high congestion. With outage of line 2-5, the optimal pool dispatch is $P_{p1} = 2.4$ MW, $P_{p2} = 185.1$ MW, $D_{p4} = 100.0$ MW, and $D_{p5} = 80.0$ MW. The bilateral contract is limited to 18.0 MW. The EM, which was –2.100, showed that system is dynamically unstable. The sensitivities $\eta_{2\rightarrow1}$ and $\eta_{3\rightarrow1}$ were calculated and found to be 3.147 and –2.635, respectively. The sign of sensitivity $\eta_{3\rightarrow1}$ shows that shift of power from generator-3 to generator-1 will not bring the system to dynamic stability.

The required shift of power from generator-2 to generator-1 was found to be 66.7 MW. With this change in power, the optimal dispatch became infeasible, which shows that it is not possible to supply all the pool demand with the exiting operating constraints. The problem was solved with some minimal curtailment of pool loads. It was found that the optimal pool dispatch is $P_{p1} = 53.0$ MW, $P_{p2} = 118.4$ MW, $D_{p4} = 93.1$ MW, and $D_{p5} = 74.3$ MW. The bilateral contract has been reduced to zero.

If the bilateral contract is held at its static security value of 18.0 MW and the pool generators dispatched optimally, case-4 is obtained. The optimal pool dispatch is found to be $P_{p1} = 43.3$ MW, $P_{p2} = 118.4$ MW, $D_{p4} = 87.6$ MW, and $D_{p5} = 69.7$ MW. These examples give interesting alternatives about different methods of applying pool protection.

The degree of curtailment calculated using (9) for all the cases 1 to 4 were found to be 0.7248, 0.5456, 1.0004, and 0.8357, respectively. It shows that case-2 is least congested and while case-3 represents the most congested case.

Conclusions: An optimal transmission dispatch methodology that takes into account consumer willingness to pay to avoid curtailment and uses sensitivity information of TEM with respect to the change in generation from critical generators to noncritical generators has been proposed in this letter. The case studies illustrate that the critical and noncritical generator pair that has the highest sensitivity is the first choice suitable for scheduling. However, depending on contractual and price obligations, other pairs with high sensitivity may be preferentially selected.

It was also observed that with some priority arrangement coordination among generators would reduce the power curtailment in both pool and bilateral transactions. The most significant result of these findings is that different philosophies of curtailment management, rescheduling in response to static and dynamic security concerns, and mixes of these strategies can be explored using these methodologies.

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Real-Time Implementation of Optimal Reactive Power Flow

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Abstract: The application of optimal reactive power flow (ORPF) to the New Brunswick (NB) Power system is presented. The potential benefits and the real-time implementation problems of ORPF are discussed. Some important issues of real-time implementation on ORPF, such as frequency of running, the number of activated control variables, and the order of adjustment of different controls, are discussed.

The application of ORPF on the NB Power network has shown two major benefits: 1) an improvement in the voltage profile and voltage stability and 2) a savings in active power loss. The improvement in the voltage profile can cause fewer violations and a more stable system from the voltage point of view. A reduction in active power loss gained from ORPF can save a significant amount of money. The total ideal savings for the year 1997 predicted in the study was in excess of $900,000, however, only 10 to 30% of this amount is realistically obtainable due to operational and other constraints. These savings can be gained simultaneously with the improvement of the voltage profiles.

Keywords: Optimal reactive power flow, power loss minimization, optimization methods

Introduction: Optimal power flow (OPF) problem is one of the major issues in the operation of power systems [1]-[6]. This problem can be divided into two subproblems, MW and MVAR dispatch. In many cases, the optimal reactive power flow (ORPF) problem is considered independently [1], and in some others it is combined with MW dispatch [2]. However, in most real-time applications ORPF has run independent of MW dispatch. The main objectives of ORPF address three important aspects: 1) to keep the voltage profiles in an acceptable range [3], 2) to minimize the total transmission energy loss [4], and 3) to avoid excessive adjustment of transformer tap settings and discrete var sources switching [5].

The control variables for this study consist of the vars/voltages of generators, the tap ratios of transformers, reactive power generation of var sources, etc. The constraints include the var/voltage limits of generators, the voltage limits of load buses, tap ratio limits, var source limits, power flow balance at buses, security constraints, etc. [5].

In most applications of ORPF, the power loss in the transmission network is minimized on the basis of a single snapshot of the network [2]. For tracking on-line load changes and keeping the network in optimal condition over time the ORPF should be executed continuously, or at least very often [6]. However, due to application and implementation difficulties, ORPF is run less frequently. Reasons for this include keeping operator workload within acceptable limits and avoiding excessive equipment switching (transformer taps, capacitor banks, etc.) [4]. An appropriate cycling time for ORPF implementation is addressed in this letter. The participation of different controls in each run of ORPF and the order of optimal adjustments are also considered. Finally, the potential benefits of real-time implementation of ORPF are discussed. The study has shown two major benefits for the NB Power network: 1) the improvement in the voltage profile and voltage stability, and 2) the savings in active power loss.

Below, the real-time implementation issues of ORPF are considered. In the third and forth sections, the frequency of the execution of ORPF and the number and order of optimal adjustments of control variables are addressed, respectively. In the fifth section, the time period and load conditions of cost benefit study are considered. The simulation results are presented in the sixth section. Finally, the concluding remarks are discussed.

Real-Time Implementation of Optimal Reactive Power Flow (ORPF) for the NB Power Network: The NB Power Company provides the electric power for the New Brunswick Province in Canada. Its network is connected to the Hydro Quebec Power system from the north and west, to Nova Scotia and Prince Edward Island power networks from the east, and to the United States' power systems from the west and south. The NB Power network is connected to these neighboring companies via 15 tie lines, including two high-voltage direct current (HVDC) links. NB Power has a peak load of 2800 MW during the winter. Its network is comprised of 35 generating units; 45 on-load tap changing transformers (LTC); and 35 switched shunts, including capacitor and reactor banks, five fixed shunts, 223 lines, and 277 buses.

NB Power owns an ORPF package, which is running on a VAX computer at the Energy Control Center (ECC). The package can be used for on-line applications. This package can be utilized in connection with other application programs, such as state estimator (SE). For on-line execution of ORPF, the SE program prepares the appropriate data for the ORPF program.

The connection between on-line data and the SE and ORPF programs is shown in Figure 1. By getting a real-time snapshot of the NB Power network, the on-line data from Supervisory Control and Data Acqusition (SCADA) are transferred to the SE program. The SE program uses the network data to calculate the necessary input data for the ORPF program. By running ORPF, the optimal operating condition of the network—including the new adjustments of control variables, voltage profiles, power loss, etc.—is obtained. By implementing the optimal settings on the network, the system moves to the optimal operating condition.

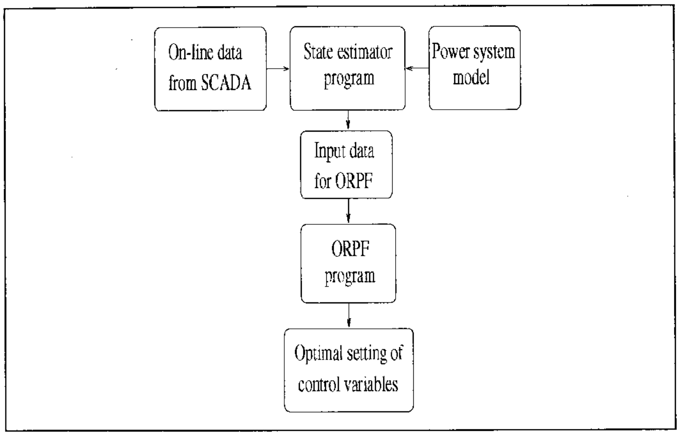

Figure 1. The connection between SCADA, SE, and ORPF programs

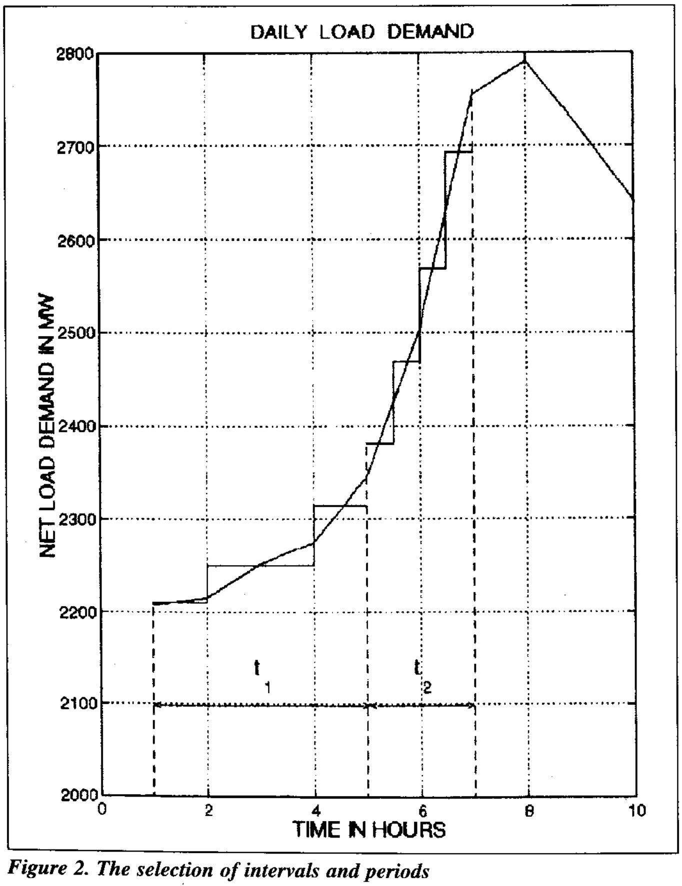

Figure 2. The selection of intervals and periods

Some major issues in the real-time implementation of ORPF, such as the frequency of control adjustments and the order of optimal adjustments, are considered in the following sections.

Frequency of Running ORPF: An important aspect in running the ORPF program is the frequency of its execution. This frequency can be varied from several minutes up to several hours. The frequency depends on some important factors, such as the load profile variation, constraint violations, importance of power loss reduction and/or maintaining an appropriate voltage profile, and the philosophy dictated by the utility company. It is also possible that different control variables be adjusted at different frequencies.

For finding the appropriate frequency of running ORPF, the daily load profile should be considered. The daily load profile of one day in January between 1 a.m. and 10 a.m. is shown in Figure 2. During the instants when the load changes rapidly, ORPF should be executed with a higher frequency. For example, between 5 a.m. to 8 a.m. the load has the highest rate of change, and ORPF should be run more often. However, during 2 a.m. to 4 a.m. the load is almost flat, and one ORPF run could be enough.

In Figure 2, two time intervals, between 1 a.m. to 5 a.m. and 5 a.m. to 7 a.m., are selected. Each interval is divided into several periods. The interval between 1 a.m. to 5 a.m. is divided into three periods. Due to small load changes in these periods, for each period one ORPF run is enough. During 5 a.m. to 7 a.m., due to rapid load changes four periods are selected. Similarly, for each period one ORPF run is enough.

Another method for running ORPF with less control action is also possible. In this approach, the control variables are divided into two categories: 1) discrete controls (tap ratios, capacitor and reactor banks) and 2) continuous controls (generator var sources). In this method, the discrete and continuous controls can be set with different frequencies. The discrete controls can be adjusted only at the beginning of intervals, while the continuous controls can be set at the beginning of intervals and periods. As an example, discrete and continuous controls can be adjusted at 1 a.m. and 5 p.m., while the continuous controls can also be adjusted at 2 a.m., 4 a.m., 5:30 a.m., 6 a.m., and 6:30 a.m. (Figure 2). Strategy decision along these lines could be made as company policy or left to the operator's discretion. The best way to find the frequency of running ORPF is by studying the load profile of each day separately. For giving some general considerations, an average daily load demand for the month of January is calculated and studied in the next section.

Frequency of Running ORPF in the Month of January: The load profile for average daily load in January 1997, which is shown in Figure 3, is considered in this section. The load level during 1 a.m. to 6 a.m. is almost flat with of an approximate value of 1700 MW. The small variation of load does not necessitate more than one ORPF run. Therefore, by running ORPF around 1 a.m. no later adjustment is necessary, unless some unexpected load changes happen.

The morning load pickup and evening drop-off have similar rates of load change. From 6 a.m. to 9 a.m. load has a substantial increase from 1700 to 2100 MW, and from 10 p.m. to 1 a.m. the load has a big drop of 300 MW. For keeping the system in optimal condition during these intervals, more frequent runs of ORPF are necessary. A cycle of 15 to 20 min can keep the system in optimal condition during these intervals. It is also possible that the discrete and continuous control variables be adjusted with different frequencies during each interval. The discrete variables can be set with a cycle of one to one and a half hours, while the continuous variables can be adjusted with a cycle of 15 min.

From 9 a.m. up to 12 p.m., the load has a value around 2100 MW. In this situation, two runs of ORPF at 9 a.m. and 11:30 a.m. should keep the system in optimal condition. In these cases, if the forecast load has an almost flat value, it is better to avoid any control action because some small fluctuation in the load may cause recurrent adjustments of the same controls in less than an hour.

Between 12 p.m. and 1:30 p.m., 4 p.m. and 6 p.m., and 8 p.m. and 10 p.m. there is a load change of 100 MW. A cycle of 30 min is an appropriate value for running ORPF in these intervals due to small load changes. From 1:30 p.m. up to 4 p.m., the load does not change substantially, and it only has a fluctuation less than 50 MW. One run of ORPF would be enough for keeping the system in optimal condition. Between 6 p.m. and 8 p.m. there is only a small reduction of 30 to 40 MW. With this small amount of load change only one run of ORPF would suffice.

As a general rule, for high rate of load changes ORPF should be run more often and for flat load periods ORPF should be executed less frequently. The appropriate cycle time can vary somewhat between 15 min up to four hours. In cases where the cycle time is less than an hour, the procedure of separating the control variables into discrete and continuous sets as mentioned above can be followed.

The Number and Order of Control Adjustments: Two important issues before and after the execution of ORPF program are considered. The number of control adjustments should be specified before running the program. The order of control adjustments must be known after the execution of the program. These two issues are discussed below.

The Number of Control Adjustments: One of the important issues in the real-time execution of ORPF program is the number of active control variables. The participation of different control variables in each run of ORPF is important for the following reasons:

1. The amount of adjustments must not cause excessive operator workload.
2. The control adjustments should be possible to execute in a reasonable amount of time.
3. The discrete controls should not be switched too frequently.

For these reasons, the discrete and continuous controls are considered separately. These two types of controls are different in several aspects:

1. In general, the continuous variables can be adjusted at the optimal values obtained from the program. However, the discrete controls can not be set at the continuous optimal values in most cases. These controls should be adjusted at the discrete values closest to the optimal values. This difference can be significant for switched shunts.
2. Generally, the var adjustment of generators does not bear major depreciation costs, however, the switching action of discrete controls can cause wear and shorten the life of the corresponding equipment.

Due to these reasons, all the generator vars may be adjusted after each run of ORPF, and they are adjusted to the optimal values to the extent which is possible, while discrete controls as mentioned earlier may not be adjusted on all of the ORPF runs. If the cycling time of ORPF is too short (15/30 min), the operator may not have enough time to adjust all the controls. In these cases, the ORPF program can be executed by only using the continuous controls.

The Order of Control Adjustments: After finding the optimal solution, the difficult task is to execute the adjustments recommended by the program. The adjustment of control variables can be performed with different strategies, such as:

1. Adjustment by the order of control variable type, e.g., first adjust switched shunts, then generators, and finally transformers;
2. Adjustment by the order of area and substation, e.g., pick up one area and do the adjustments in that area by selecting one substation at a time;
3. A combination of methods 1 and 2.

The third method seems to perform most efficiently. A detailed procedure for doing the adjustments according to this approach is described below:

Step 1: The adjustment of control variables starts with the switched shunts. They are adjusted one by one if no violations are observed. If all the switched shunts are adjusted without any bus voltage violation, the adjustments continue by skipping to Step 3. During these adjustments, it is also possible that the automatic tap changing transformers (LTC on automatic mode) automatically change their tap ratios if the bus voltages move out of some preset ranges. In any case, if any bus voltage violation is observed, the switched shunt adjustments are stopped and the procedure in Step 2 will be followed.

Step 2: After finding the closest transformers and/or generators to the violated bus voltage(s), their recommended adjustment by the program will be performed. In most cases, after one or two adjustments the bus voltage violation(s) will be removed, and the order of adjustment continues by returning to Step 1.

Step 3: In this step, all the generator vars are adjusted. If no bus voltage violations are observed, the generators are moved to the optimal

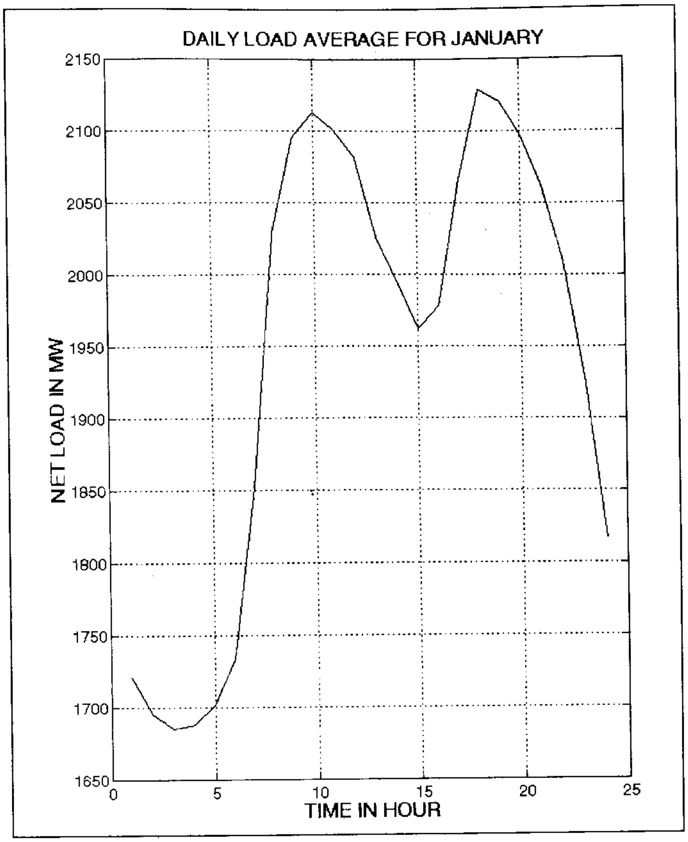

Figure 3. The average daily load of January 1997

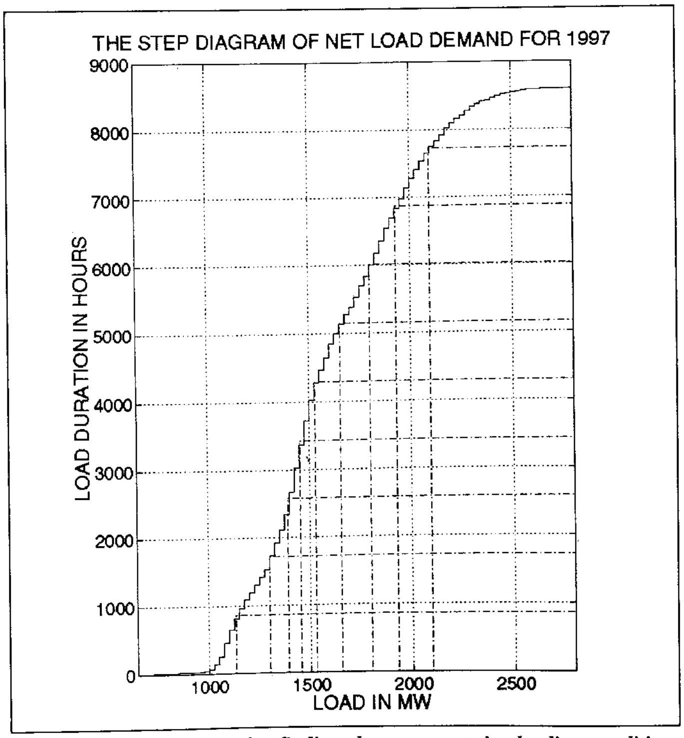

Figure 4. The procedure for finding the representative loading conditions from step diagram

Table 1. The representative loading conditions in Figure 4 for N=10											
Case No.	1	2	3	4	5	6	7	8	9	10	11
Load level in MW	675	1134	1299	1393	1454	1528	1653	1801	1932	2096	2800

values one by one. If any bus voltage violation is predicted during the adjustment of one control, some correcting actions should be devised. The problem can be solved by the procedure explained in Step 4, or by limiting the movement of the related control.

Step 4: The closest transformers to the violated bus voltage(s) are found. The tap ratios of these transformers are moved to the optimal values recommended by the program to remove the probable violation(s). After removing the violation(s), the remaining adjustments of Step 3 continue.

Step 5: In this step, all the switched shunts and generators are previously adjusted, and only the tap ratios should be adjusted. In this stage, all the transformer tap ratios are moved to the optimal values recommended by the program if no violation occurs. In the case of probable voltage violations, the control action can be performed partially.

The effects of real-time implementation of ORPF on the NB Power network, including the changes on the voltage profile and the total dollar savings during a one-year interval, are discussed in the following sections.

Study Period: The effects of on-line ORPF on the NB Power network have been studied for the load conditions of one year. The load data is related to the historical hourly net load of the year 1997. These data include 8760 (365*24) load points. Each load level has a duration of one hour. For totally accurate study of the yearly average savings, all of these cases should be studied. As is apparent, the simulation of all the loading levels is very time consuming and tedious. By using statistical sampling methods a representative set of cases can be studied yielding accurate results. The representative loading conditions are selected by using the statistical analysis of the yearly load profile as given in the next section. For each case, by running the ORPF program the savings in power loss can be found and the results are generalized for the whole year. These savings can be easily transformed to energy savings, and then by multiplying by the price of electric energy ($/MWH) the dollar savings can be obtained.

The Selection of Representative Loading Conditions: The representative loading conditions are selected on the basis of a step diagram related to class interval of 25 MW (see Appendix A). The procedure for finding these points is shown in Figure 4 and explained below:

1. The ordinate axis between zero and the maximum load duration time are divided into N equal sections (N = 10). By drawing horizontal lines at these points, 11 points on the step diagram will be found.

Table 2. The study results of ORPF program for the representative loading conditions				
Case No.	Total Net Load*	P_L before ORPF	P_L after ORPF	P_L Saving
1	940	27.9	25	2.9
2	1140	39.8	37.1	2.7
3	1340	52.7	49	3.7
4	1405	78.1	73.4	4.7
5	1460	58.8	54.1	4.2
6	1530	58.7	54.9	3.8
7	1655	75.1	70.5	4.6
8	1825	94.2	88.9	5.3
9	1920	119.2	113.5	5.7
10	2036	88.3	83	5.3
11	2332	1109	104.1	6.8

* All the values of powers are in MW.

2. The points that are found on the step diagram are projected on the abscissa axis. Eleven equivalent points will be found on this axis. Two of these points are related to minimum and maximum loads, and the other points pertain to the light to heavy load conditions. These points constitute the representative loading conditions and will be used for power loss minimization purposes.

The loading levels found from the above method are given in Table 1. Note that each level is approximately representative of 9% of the load distribution. The average in power loss savings for all these cases gives an acceptable value for the average yearly savings in power loss.

Study Results: *ORPF Studies for the Selected Representative Loading Conditions*: In this section, the loading conditions that are obtained above are used for ORPF benefit study purposes. Network data for each loading condition are obtained by getting a real-time snapshot from the NB Power system. The procedure for power loss minimization for each load level is as follows:

1. A loading condition that is close enough to a representative loading condition (Table 1) is obtained by getting a snapshot in real time.

2. The power loss and the load flow data for the operating condition are saved for later comparison.

3. The ORPF program is executed. The output of the program gives the optimal operating condition including the power loss, the voltage profile of buses, the settings of different control variables, and probable constraints violations.

Two types of analysis can be done on the basis of these ORPF runs: 1) the improvement in the voltage profile of NB Power network and 2) the reduction in power loss. The improvement in the voltage profile can be obtained by comparing the bus voltage violations of the actual operating condition with those of the optimal state. For each load level, by subtracting the power loss of the actual and optimal conditions, the savings can be found. The arithmetic mean of these savings values will give an acceptable value for the yearly average savings in the power loss of the NB Power network.

Calculation of the Yearly Average Savings for the NB Power Network: The loading conditions obtained from snapshots are studied for power loss minimization purposes. The results of ORPF studies for these load levels are shown in Table 2. The actual loading conditions, which are used for simulation studies, are given in the second column of Table 2. The power loss for these loading conditions, via the procedure mentioned in the previous section, is minimized. The power loss for each load level before and after running the ORPF program are given in the third and fourth columns of Table 2, respectively. The savings in power loss for each loading condition is given in the fifth column of Table 2.

Simulation results are also shown in Figure 5. The power loss in MW and the percentage of total load versus the related load level are illustrated in Figure 5(a) and (b), respectively. Power loss savings in MW and the percentage of total load versus the related load levels are depicted in Figure 5(c) and (d), respectively.

The yearly average savings of power loss is equal to the arithmetic mean of power loss savings given in Table 2. This average value will be equal to

$$P_{\text{avr}}^{\text{yearly}} \approx 4.52\ \text{MW}.$$

The yearly average dollar savings can be calculated by the multiplication of yearly energy loss savings in MWH by $25/MWH as

$$4.52 * 8760 * 25 \approx \$990{,}000.$$

It should be noted that only 10 to 30% of this amount is realistically obtainable due to operational and other constraints.

Another impact of on-line ORPF on the NB Power network is its effect on the voltage profile. The voltage profile can be considered as the

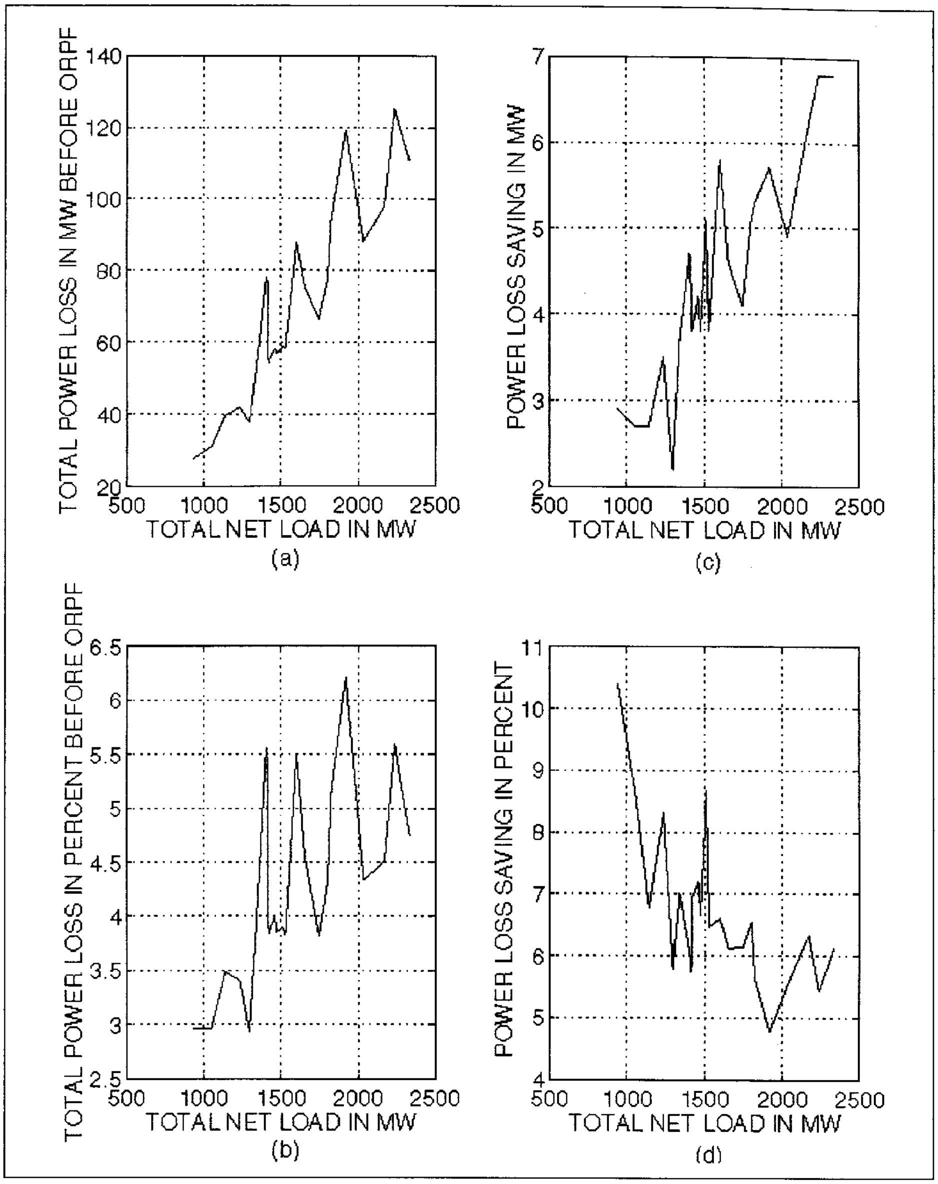

Figure 5. The power loss and its saving for loading conditions obtained from snapshots

bus voltage violations and/or the average level of bus voltages in the network. In most cases, the ORPF program comes to a solution within the bus voltage limits. The bus voltage profile obtained from the snapshot shows all the bus voltage violations before running the ORPF program. In several cases, the bus voltage violations up to ten buses were observed in real-time snapshots and were removed by running the ORPF program. Another issue in the comparison of bus voltages before and after running ORPF program is the voltage level of the buses. The change of all bus voltages due to ORPF can be presented by their average value. In one studied case, the average value of bus voltages is increased by 2.2% after running the ORPF program.

Conclusion: Some of the important issues and the potential benefits of the real-time implementation of ORPF for the NB Power network have been demonstrated. Some basic considerations for the selection of ORPF cycling time, the activated control variables, and the order of optimal adjustment of controls are addressed. For cost benefit calculation, the loading conditions of the whole year of 1997 were studied. By using statistical analysis, several representative loading conditions were selected. The ORPF program was executed for all of these loading levels. The study results of these representative loading conditions can be generalized to the entire year with good accuracy.

From the study and implementation results, two main points are justified: 1) a significant savings in active power loss can be achieved and 2) the voltage profiles and stability of the NB power network can be improved. The total ideal savings for the year 1997 predicted in this study was in excess of $900,000. However, the real power loss savings achievable by a practical implementation of ORPF may be 10 to 30% of the idealized results presented here. Operational and other constraints might reduce the savings substantially. These savings can be gained simultaneously with the improvement of the voltage profiles. In other words, by running the ORPF program and adjusting the network accordingly, not only will the power loss be decreased but bus voltage violations will also be removed. This leads to a more economical operating condition and at the same time to a more secure system from the voltage point of view.

Appendix A—Basic Definitions for Statistical Analysis: *Class Interval*: For any type of statistical study, it is meaningful to classify the load range into several classes. Each class includes a specific number of loading conditions. The difference between the upper and the lower load levels of each class is called *class interval.*

Histogram: A graph that represents the class intervals on the x-axis and the duration of each class on the y-axis is called *histogram.*

Step diagram: The duration of load levels that are at or less than a given value, rather than the duration of each specific load level, is presented by step diagram (see Figure 4). The step diagrams are directly constructed from histograms.

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