Dispatching Reactive Power Considering All Providers in Competitive Electricity Markets

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***Abstract*—This paper proposes a level playing field for the supply of reactive power ancillary services, wherein not only synchronous generators, but other providers of reactive power are also paid for their services. An Optimal Power Flow (OPF)-based reactive power dispatch model is proposed based on the reactive power payment mechanisms existent in Ontario. Novel cost models are proposed for Static VAR Compensators (SVCs) and Static Synchronous Compensators (STATCOMs) and included in the dispatch model. The proposed methodology is tested on a dispatch model of Ontario power grid, and the results show that the proposed technique can significantly reduce the cost of reactive power dispatch while maintaining system security.**

***Index Terms*- Electricity markets, reactive power dispatch, SVC, STATCOM.**

I. Nomenclature

A. Parameters

HOEP:	Hourly energy Ontario price in $/MWh.
P_{Gi}:	Active power generation at bus *i* in p.u.
$Q_G^{\min}$:	Minimum reactive power limit of a generator.
P_{Di}:	Active power demand at bus *i* in p.u.
Y_{ij}:	Element of admittance matrix in p.u.
θ_{ij}:	Angle associated with Y_{ij} in radians.
Q_{Di}:	Reactive power demand at bus *i* in p.u.
$Q_{Gg}^{\min}$:	Minimum reactive power of generator *g*, in p.u.
Q_{SVC}^{rated}:	Rated VAR capacity of SVC in p.u.
$Q_{STATCOM}^{rated}$:	Rated VAR capacity of SVC in p.u.
ρ_{B1}:	Price of upward balance services in $/MWh
ρ_{B2}:	Price of downward balance services in $/MWh
$P_{B1i}^{\max}$:	Maximum upward balance service at bus *i* in p.u.
$P_{B2i}^{\max}$:	Maximum downward balance service at bus *i* in p.u.
$V_i^{\max}$:	Maximum allowable voltage at bus *i,* in p.u.
$V_i^{\min}$:	Minimum allowable voltage at bus *i,* in p.u.
$P_{ij}^{\max}$:	Maximum power flow from bus *i* to bus *j*, in p.u.
B_{SVC_L}	SVC minimum inductive susceptance in p.u.
B_{SVC_C}	SVC maximum capacitive susceptance in p.u.
$I_{STATCOM\_L}$	STATCOM maximum inductive current in p.u.
$I_{STATCOM\_C}$	STATCOM minimum capacitive current in p.u.
b_{SVC}:	Fixed cost component of O_{SVC}, $/p.u.
a_{SVC}:	Variable cost component of O_{SVC} $/p.u.

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B. Variables:

O_{SVC}:	SVC offer curve.
Q_{Gi}:	Generator reactive power at bus *i* in p.u.
P_{B1i}:	Upward balance service at bus *i* in p.u.
P_{B2i}:	Downward balance service at bus *i* in p.u.
V_i:	Bus *i* voltage magnitude in p.u.
δ_i:	Bus *i* voltage angle in radians.
P_{ij}:	Power flowing from bus *i* to bus *j*, in p.u.
δ_i:	Power flowing from bus *i* to bus *j*, in p.u.
Q_{SVC}:	SVC reactive power in p.u.
$Q_{STATCOM}$:	STATCOM reactive power in p.u.
B_{SVC}:	SVC susceptance in p.u.
$I_{STATCOM}$:	STATCOM current in p.u.
$Loss_{SVC}$:	SVC active losses in p.u.
$Loss_{STATCOM}$:	STATCOM active losses in p.u.
$Loss_{Gg}$:	Active losses in generating unit *g* in p.u.

II. Introduction

REACTIVE power dispatch is a critical short-term function carried out by power system operators in order to operate the system in a secure manner. The traditional reactive power dispatch paradigm based on minimization of losses has gradually given way to new criteria such as reactive power payment minimization [1]. In the recent literature, a two-tier structure for the management of reactive power has been proposed in the context of competitive electricity markets [2]-[4]. The latter propose that the problem of reactive power management be split into a procurement problem and a dispatch problem, with the procurement problem being essentially a long-term issue of contracting appropriate set of generators for the service provision, whereas the dispatch problem deals with allocation of reactive power generation to the units in the real-time.

In the procurement problem, the Independent System Operator (ISO) seeks to identify the generators that are critical for providing reactive power support, considering the overall system security. In [2] and [4], the problem is treated as a generator bidding process on a seasonal basis to avoid potential problems associated with the effects of price volatility of energy markets on reactive power prices. With the help of first a maximum loadability Optimal Power Flow (OPF) and then a security-constrained OPF, the ISO determines, based on reactive power offers, zonal reactive power price components and the key sets of suppliers. Once the reactive power prices are known from the procurement stage, the dispatch problem is carried out close to real-time to optimally allocate the system reactive power demand to suppliers; this process is based on an OPF that minimizes the total ISO costs associated with reactive power dispatch subject to security constraints [3], [4].

In its 1996 Order No.888, the Federal Energy Regulatory Commission (FERC) had recognized reactive power supply and voltage control services from synchronous generators as one of the six ancillary services that transmission providers must include in their open access transmission tariff. It is also stated that reactive power from capacitors and FACTS controllers, that form part of the transmission system, were *not* separate ancillary services [5]. However, there are recent recommendations from FERC to recognize reactive power provisions from sources other than synchronous generators, as ancillary services, so that they are eligible for financial reimbursement [6].

In Ontario, synchronous generators are paid for the real power losses (MW-losses) incurred when operating at non-unity power factors. Payments are made at the Hourly Ontario Electricity Price (HOEP) rates based on calculated generator losses for the hour. There is no payment for reactive capability within the standard power factor range; in other words, there is no payment in Ontario for the costs of equipment such as exciters which are deemed essential for real power production by all generators. To avoid economic distortion because of possible large revenues for generators operating solely within standard power factor ranges, capability payment for reactive power is ignored in Ontario. Alternative var suppliers such as capacitors, reactors, Static Var Compensators (SVCs) and Static Synchronous Compensators (STATCOMs) are eligible for payments for their costs of installing and maintaining the equipment [7].

It has been discussed and demonstrated in [8] that if synchronous generators are the only reactive power ancillary service providers in the system, significant possibilities of market power can arise at certain buses in the system. It was suggested therein that in order to alleviate such situations, the reactive power market be a *level playing field* wherein all reactive power providers are considered ancillary service providers and be eligible for payment. Such a suggestion is also in line with FERC recommendations [6]. In [9], a reactive power capacity market is proposed wherein the ISO procures reactive power capacity through annual auctions; the optimal capacity is determined considering offers from generators and other sources of reactive power such as capacitors and SVCs.

In view of the above, the main objective of this paper is to propose and present a *level playing field* reactive power dispatch model that can address the problems of reactive power market inefficiencies and bring in more fairness and competition in reactive power ancillary service provisions. The proposed dispatch model seeks to minimize the ISO's total cost of reactive power dispatch, incurred through payments to the service providers, while maintaining the security of the system. It should be pointed out that, unlike [2], [3], [4] and [8], this work does not consider var price offers from the service providers, so that it is more in line with the practice of the Independent Electricity System Operator (IESO) of Ontario, which is the Control Area operator in Ontario responsible for administering the wholesale electricity market. The reactive power suppliers are paid for their active power losses (MW-losses) incurred because of reactive power provision, at the HOEP rate as in Ontario.

The approach proposed in this paper differs from that of [2]-[4] in some other aspects as well. Firstly, the procurement model is not considered here, since the framework does not require submitting price offers for reactive power. Secondly, the ISO's payment objective function has been modeled in this paper to resemble the IESO's practice, whereas in [3] and [4] the payment objective was based on reactive power dispatch and active power redispatch. Lastly, the work takes into account the presence in the dispatch model of other sources of reactive power such as capacitors, reactors, SVCs and STATCOMs, which are recognized eligible for payment for their reactive power ancillary service.

The rest of the paper is organized as follows: In Section III the cost of reactive power provision for static VAR compensators is discussed. The reactive power dispatch model is introduced in Section IV, and is based on the optimal allocation of reactive power demand to suppliers while minimizing their MW-losses, i.e. minimizing the reactive power dispatch costs for the ISO. The results from the application of the models to the IESO-controlled grid dispatch model, which is comprised of 2,833 buses and 4,205 branches, are presented and discussed in Section V. Concluding remarks and a highlight of the main contributions of the paper are provided in Section VI.

III. Cost of Reactive Power for Shunt Compensators

The dominant cost of reactive power production from shunt compensators such as SVCs and STACOMs can be decomposed into two cost components: (1) cost of installed var capacity, and (2) cost of operation. The investment cost of SVC/STATCOM is typically in the range of 40 to 50 \$/kvar [10]-[11]. Considering a lifetime of 20 years and a discount rate of 8%, the amortized cost is in the range of 4.07 to 5.1 \$/kvar-year, or equivalently 0.46 to 0.58 \$/Mvarh.

Active power losses constitute a major part of the SVC operating cost, and is typically in the range of 0.5 to 0.75% of the reactive power output [12]-[13]. For STATCOMs, the variable cost is essentially associated with the losses in the converter which, at the rated output, are higher than for comparable SVCs [14]; these losses are typically less than 1% of the reactive power output [10].

In order to arrive at a typical range for the variable cost of SVCs and STATCOMs, the following assumptions are made:

- The SVC/STATCOM is fully utilized 40% of the time.
- The HOEP is in the range of 80 to 100 \$/MWh, which is a typical high price in the Ontario market.
- The total active power losses in the SVC/STATCOM are approximately 1% of the reactive power output.

Given the above assumptions, the total generated reactive power for a 1 Mvar SVC/STATCOM in a year would be 40% × 1 Mvar × 8760 h = 3504 Mvarh, and the corresponding active power losses are then 1% × 3504 Mvarh = 35.04 MWh. Therefore, the annual cost of losses at the HOEP rate would be 35.04 MWh × 80-100 \$/MWh = \$2,803-\$3,504, which yields an approximate variable cost of 0.032-0.040 \$/Mvarh. These calculated values can be used for both SVC and STATCOM, provided the aforementioned assumptions hold true. In addition to the active power losses which vary with the output level of the SVC/STATCOM, the device incurs losses even when it does not supply any reactive power. These no-load losses are typically estimated at 0.1% of the SVC/STATCOM rating [10].

In order to ensure that the investment cost in the SVC/STATCOM is recovered, the device should be paid for both its fixed and variable costs. Hence, the offer curve for reactive power supplied by the SVC/STATCOM would consist of two components as follows:

$$\begin{aligned} O_{SVC} &= b_{SVC}\, Q_{SVC}^{rated} + a_{SVC}\, Q_{SVC} \quad \$/\text{h} \\ b_{SVC} &= [0.46, 0.58] \quad \$/\text{Mvarh} \\ a_{SVC} &= [0.032, 0.040] \quad \$/\text{Mvarh} \end{aligned} \tag{1}$$

The parameters in this equation are based on the aforementioned discussions. Equation (1) can also be used for the STATCOM.

The active power losses in SVCs and STATCOMs can be calculated based on their loss curves, which yield the active power losses in the device with respect to the reactive power output level [15]. The active power losses in an SVC in p.u. at an operating point Q_{SVC} are given by:

$$Loss_{svc} = (0.00625 Q_{svc}{}^{2} + 0.00175)\, Q_{svc}^{rated} \quad \text{p.u.} \tag{2}$$

And similarly for the active power losses in the STATCOM. The compensator is then paid for active power losses at the HOEP rate, as per the IESO current practices, plus an uplift payment to account for the fixed costs, as described in the next section.

Similarly to SVCs and STATCOMs, the cost incurred by a generator for reactive power production can be decomposed into two parts. A fixed part associated with the difference between the plant building costs with and without a reactive power margin, and with the equipments needed to maintain that margin [16]; this fixed component is ignored in the reactive power dispatch. The variable part is primarily due to active power losses (MW-losses) associated with the reactive power output. For synchronous generators, these losses are classified into Joule, eddy, hysteresis and stray losses, mechanical losses, and exciter losses. Typical experimental curves for losses in the rotor, stator and step-up transformer as a function of reactive power injection are provided in [16] for a given nominal active power. Based on these loss curves, the loss function approximating the total real power losses in the main and auxiliary parts of a typical generator can be represented by:

$$Loss_{Gg} = 6\times10^{-5} Q_{Gg}{}^{2} + 25\times10^{-3} Q_{Gg} + 2.9 \quad \text{MW} \tag{3}$$

where Q_{Gg} is the generator reactive power in Mvar for generator g. Observe that the total losses are minimal for a certain amount of *absorbed* reactive power since $Q_{Gg} < 0$, which is not the case for *injected* reactive power.

The loss functions approximating total MW-losses for generators and SVCs/STATCOMs (2) and (3), respectively, are used in the Q-dispatch model to calculate the MW-losses and the corresponding payment to reactive power suppliers, as described next.

IV. Proposed Level Playing Field Q-Dispatch Model

Ideally, reactive power should be dispatched in an economical manner to minimize transmission losses and active losses of generating facilities while keeping the system secure. Considering the complexities involved in supplying reactive power in deregulated electricity markets, a method for reactive power dispatch is proposed here that is suitable for real-time applications. Given that the active power dispatch levels of the generators are known from energy market clearing, the ISO can determine the reactive power dispatch using an OPF-based model which minimizes the total active power losses of reactive power suppliers subject to system security constraints. In this approach, the suppliers of reactive power including generators, SVCs and STATCOMs are assumed to be paid for their real power losses, which is the payment mechanism presently used in Ontario.

It must be mentioned that synchronous generators in the Ontario electricity market are paid if they are required to operate outside their standard power factor range and thereby reduce their real power output. In such circumstances, generators are paid for their lost opportunity cost based on the reduction in generation level including losses at the HOEP rate [7]. Since this situation seldom arises in Ontario, in the dispatch model presented here it is assumed that generators are not allowed to operate in the opportunity region and are therefore only paid for their active power losses.

Based on the loss equations (2) and (3) for generators and SVCs/STATCOMs, the level playing field reactive power dispatch problem can be formulated as a security-constrained OPF to minimize the total active power losses of reactive power suppliers. The objective function of the problem can then be defined as follows:

$$\begin{aligned} J_1 = & \sum_g HOEP\, Loss_{Gg} \\ & + \sum_m (HOEP\, Loss_{SVCm} + b_{SVCm}\, Q_{SVCm}^{rated}) \\ & + \sum_k (HOEP\, Loss_{STATCOMk} + b_{STATCOMk}\, Q_{STATCOMk}^{rated}) \end{aligned} \tag{4}$$

where J_1 represents the total cost of reactive power dispatch in \$/h, which is based on the calculated losses and the *HOEP* rate in \$/MWh. The first term in (4) refers to the active power losses in the generator, the second term represents the active power losses in the SVC, and the last term denotes the active power losses in the STATCOM. Note that in (4), SVCs and STATCOMs are paid for both the variable and fixed costs of reactive power generation. If the device is not dispatched, the payment associated with the variable component will be zero; however, it is assumed that it will be paid for the fixed cost component if available for dispatch. Observe that these fixed costs do not affect the optimization process and can be removed from (4); however, they are taken into account during the payment process.

The reactive power dispatch is then based on the following OPF model:

$$\text{min.} \quad J_1 \tag{5}$$

$$\text{s.t.} \quad P_{Gi} - P_{Di} = \sum_j V_i V_j Y_{ij} \cos\left(\theta_{ij} + \delta_j - \delta_i\right) \quad \forall i \tag{6}$$

$$\begin{aligned} & Q_{Gi} - Q_{Di} - Q_{SVCi} - Q_{STATCOMi} = \\ & -\sum_j V_i V_j Y_{ij} \sin\left(\theta_{ij} + \delta_j - \delta_i\right) \quad \forall i \end{aligned} \tag{7}$$

$$V_i^{\min} \le V_i \le V_i^{\max} \quad \forall i \tag{8}$$

$$\left| P_{ij}\left(V, \delta\right) \right| \le P_{ij}^{\max} \quad \forall ij \tag{9}$$

$$Q_{Gg}^{\min} \le Q_{Gg} \le Q_{Gg}^{\max} \quad \forall g \tag{10}$$

$$Q_{SVC} = V_{SVC}\, B_{SVC}{}^2 \tag{11}$$

$$Q_{STATCOM} = V_{STATCOM}\, I_{STATCOM} \tag{12}$$

$$B_{SVC\_Lm} \le B_{SVCm} \le B_{SVC\_Cm} \quad \forall m \tag{13}$$

$$I_{STATCOM\_Ck} \le I_{STATCOMk} \le I_{STATCOM\_Lk} \quad \forall k \tag{14}$$

Equations (6) and (7) represent the nodal active and reactive power flow equations, respectively. Constraints (8) and (9) impose security limits on the bus voltages and transmission flows, and (10) restricts the generator reactive power to be within its limits. Equations (11) and (12) model the reactive power generated by the SVC and STATCOM, respectively, as the former is basically an impedance based controller, whereas the former is fundamentally a controllable voltage source [10], [15]. The relevant limits on the SVC susceptance and STATCOM current are imposed through constraints (13) and (14), respectively.

The solution to the OPF problem (5)-(14) yields the optimum levels of reactive power dispatch and the payment to each supplier. Note that in this OPF problem, the reactive power supplied by capacitors and reactors has not been considered; nevertheless, if the loss curves of these devices are available, the inclusion of the corresponding costs is straightforward.

It is assumed that the MW-dispatches of generators are known and remain unchanged during the reactive power dispatch process. Based on current IESO procedures, if there is a need for real power rescheduling in the OPF model (5)-(14) due to reactive power dispatch or voltage control needs, the required amount is allocated to the slack bus in the system.

In certain market structures, balancing services may be used to make up for the real power unbalance between the energy dispatched and the demand, as discussed in detail in [3], [4]. In this case, the objective function can be changed to:

$$\begin{aligned} J_2 = & \sum_g HOEP\, Loss_{Gg} \\ & + \sum_m (HOEP\, Loss_{SVCm} + b_{SVCm}\, Q_{SVCm}^{rated}) \\ & + \sum_k (HOEP\, Loss_{STATCOMk} + b_{STATCOMk}\, Q_{STATCOMk}^{rated}) \\ & + \sum_i \left(\rho_{B1}\, P_{B1i} + \rho_{B2}\, P_{B2i} \right) \end{aligned} \tag{15}$$

where the last term denotes the payment towards balance services. The required energy upward or downward balance services are represented by P_{B1} and P_{B2}, respectively, with the corresponding costs ρ_{B1} and ρ_{B2}, and limits:

$$P_{B1,2i} \le P_{B1,2i}^{\max} \tag{16}$$

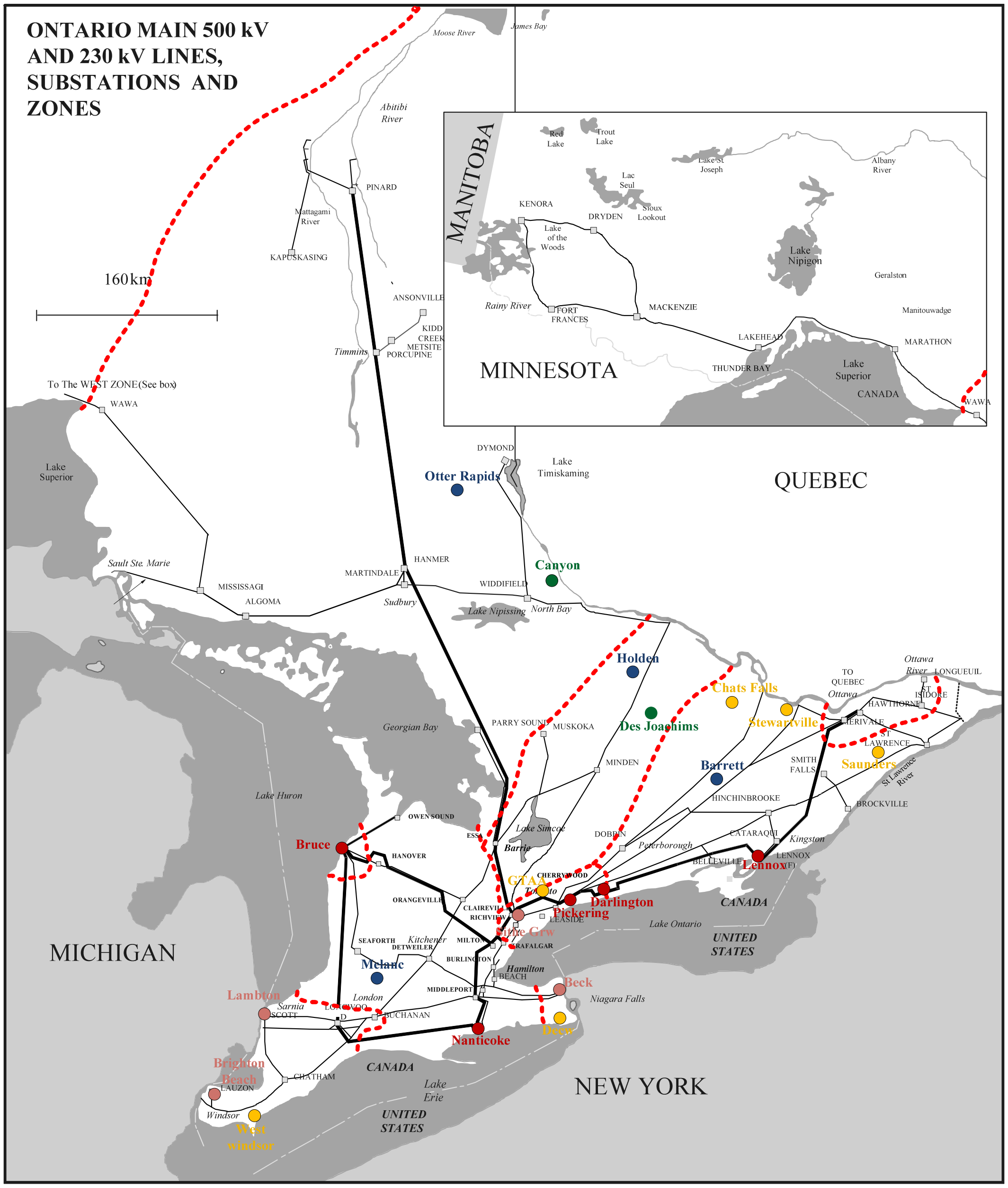

Fig. 1 the IESO-controlled grid [18]

In this case, the nodal active power flow equations need to be modified as follows:

$$P_{Gi} + P_{B1i} - P_{B2i} - P_{Di} = \sum_j V_i V_j Y_{ij} \cos\left(\theta_{ij} + \delta_j - \delta_i\right) \quad \forall i \tag{17}$$

Therefore, the OPF in this case consists on minimizing J_2 subject to constraints (7)-(14), plus (16) and (17).

The reactive power dispatch problem (5)-(14), or its corresponding balance service version, is a Nonlinear Programming (NLP) problem that was implemented in the AMPL environment and solved using the IPOPT solver [17]. The solution basically yields the optimal reactive power dispatch for each supplier.

V. Ontario Grid Case Study

The IESO-controlled grid was used to test the application of the proposed Q-dispatch model. This is the portion of the Ontario power system that is controlled by the IESO, and includes all transmission lines at voltage levels 50 kV or greater. The system interconnects with two provinces in Canada (Manitoba and Quebec) and three states in the United States (Michigan, Minnesota and New York). The total length of the transmission lines is about 31,000 km. The installed generation capacity in Ontario is about 31,000 MW with a peak demand of nearly 27,000 MW [18].

The reduced version of the IESO-controlled grid employed for dispatch purposes by the IESO was used for the studies presented and discussed here. This grid model

TABLE I
LOSSES FOR DIFFERENT COMPENSATOR LOCATIONS

Comp. Bus	Comp. Output (Mvar)	P Reschedule (MW)	Comp. Losses (MW)	Trans. Losses (MW)
No SVC	0	-15	0	668
760	107	-19	0.9	668
842	79	30	0.56	664
760 & 842	188	24	1.52	663

TABLE II
PAYMENTS FOR DIFFERENT COMPENSATOR LOCATIONS

Comp. Bus	Gen. Losses (MW)	Comp. Payments ($/h)	Gen. Payments ($/h)	Total Payments ($/h)
No SVC	495.4	0	59,449	61,249
760	493.3	156	59,210	61,637
842	494.3	118	59,318	63,037
760 & 842	492.4	283	59,083	62,246

TABLE III
DISPATCH RESULTS FOR DIFFERENT COMPENSATOR LOCATIONS: CONTINGENCY CASE (LINE 565-578 OUTAGE IN GTA)

Comp. Bus	Comp. Payments ($/h)	Comp. Output (Mvar)	Trans. Losses (MW)	Gen. Losses (MW)
No SVC	0	0	670	496
760	159	108	667	494
842	125	85	666	495
760 & 842	292	195	665	492

consists of 2,833 buses and 4,205 branches, and its main features are depicted in Fig. 1.

The system peak load of 27,000 MW was chosen as the base case, and thirteen N-1 and N-2 critical contingencies were considered, as per IESO recommendations. The proper placement for the SVCs/STATCOMs was determined through a sensitivity analysis of the maximum transfer capability of the system with respect to reactive power compensation. Thus, maximum loadability margins, which were used in lieu of system transfer capabilities, were calculated using a maximum loadability OPF model [2], [4]. The Lagrange multipliers associated with the solution of this OPF model provide the required sensitivities; thus, the optimal buses for shunt compensation placement are those with the largest Lagrange multiplier values. This procedure yielded fifty buses out of 2,435 eligible buses under normal operating conditions, all located in the Greater Toronto Area (GTA), which accounts for 40% of Ontario's total demand, with heavy power transfers from Southern and Western Ontario during peak-load conditions. Each optimal location was then examined against the IESO recommended critical contingencies; if for a given rating the compensator was able to maintain the system secure for the considered contingencies, the corresponding bus was ranked higher. This analysis identified Buses 760 and 842 in the GTA as the best locations for SVC/STATCOM placements for both normal and contingency conditions. The output level of the SVCs/STATCOMs was then determined from the solution of the proposed dispatch OPF model as discussed next.

TABLE IV
DISPATCH RESULTS WITH AND WITHOUT BALANCING SERVICES
(SVCS AT BOTH BUSES 760 &842)

Model	Trans. Losses (MW)	Q Payments ($/h)	Balance Service + Resched. Payments ($/h)	Total Payments ($/h)
Without balancing services	663	59,321	2,880	62,246
With balancing services	710	60,093	3,350	63,442

TABLE V
DISPATCH COST COMPARISONS

Method	Q-dispatch Loss Payments ($/h)	Slack-bus Payments ($/h)	Total Payments ($/h)
Proposed	59,449	1,800	61,249
Existent	67,844	2,760	70,604

The MW-losses from all reactive power providers were assumed to be reimbursed at an HOEP of $120/MWh, which is a typical high energy price during peak-load conditions. The upward and downward balance services were assumed to be priced at $110/MWh and $90/MWh, respectively, based on the IESO payment procedures for these kinds of services. The same loss equation was used for all generators, irrespective of their type. The reactive dispatch problem was then solved for the following cases: no SVCs; an SVC placed at each one of the two identified critical buses; and two SVCs placed at the corresponding critical buses. Similar scenarios were considered and studied for STATCOMs, but since the results obtained were practically the same as those for the SVCs, these are not presented here.

The dispatch results for the various cases considered are shown in Tables I and II. Observe that with no SVCs in the system, transmission losses are the highest, while with two SVCs these losses are the lowest, as expected. In all cases, SVCs supply reactive power to the system, and there is a need for real power rescheduling, as anticipated. The required MW-rescheduled amount is supplied by the slack bus and is paid by the IESO at the HOEP. The total payment to the SVC includes payments for losses at the HOEP, and for fixed costs at a price of 0.50 $/Mvarh.

Table III shows the dispatch results for a contingency case, corresponding to a critical single line outage in the GTA where both SVCs are located. As expected, the SVC output increases due to the need for additional reactive power supply to maintain the system secure. Observe as well that transmission losses increase with respect to normal operating conditions.

Table IV shows the OPF results for the models with and without balancing services, and with both SVCs placed in the system. Observe that the IESO payments and transmission losses are higher for the model with balancing services.

Lastly, Table V compares the total IESO payments for the proposed method with respect to the existent reactive power dispatch approach in Ontario. For the latter, the IESO uses ordinary power flows to determine the generator terminal voltages that maintain the system secure; the generators are then paid for the MW-losses (measured quantities) required to maintain the requested terminal voltages. For these studies, no SVCs were placed in the system and the required real power rescheduling was allocated to the slack bus. Observe that the total cost of Q-loss payment and the total cost of reactive power are lower for the proposed method compared to the existent approach. Thus, the proposed method would bring savings to the IESO of $9,355/h under peak loading conditions, which take place about 5% of the time during the year, resulting in over $4 million yearly savings.

It should be noted that the proposed reactive dispatch models were computationally efficient. Thus, it required on average 43 iterations corresponding to about 7.2s of CPU time in an IBM server with 4 Intel Xeon 2.8GHz processors and 32 GB RAM running 32-bit MS Windows.

VI. Conclusions

A dispatch method for reactive power which minimizes the active losses in reactive power suppliers while considering system security was proposed and described in detail. Generators and static var compensators such as SVCs and STATCOMs were considered and represented in the proposed dispatch model, assuming that their services are paid in terms of their active power losses at the market energy price, as per Ontario's reactive power payment procedures. The proposed model was tested and compared using the Ontario's dispatch grid model, demonstrating that, even though there is no reactive power dispatch mechanism per say in the Ontario's grid and electricity market, the proposed method may reduce the cost of reactive power dispatch while maintaining system security. It is also shown that the method is computationally efficient and appropriate for real-time dispatch applications.

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