Smart Flexible Just-in-time Transmission and Flowgate Bidding

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***Abstract*—There is currently a national push to create a smarter grid. Currently, the full control of transmission assets is not built in network optimization models. With more sophisticated modeling of transmission assets, it is possible to better utilize the current infrastructure to improve the social welfare. Co-optimizing the generation with the network topology has been shown to reduce the total dispatch cost. In this paper, we propose the concept of just-in-time transmission. This concept is predicated on the fact that transmission that is a detriment to network efficiency can be kept off-line when not needed and, with the proper smart grid/advanced technology, can be switched back into service once there is a disturbance. We determine which lines to have off-line based on the optimal transmission switching model previously proposed. A secondary topic of this paper focuses on flowgate bidding. Approved by the Federal Energy Regulatory Commission and implemented within the SPP and NYISO networks, flowgate bidding is defined as allowing a line's flow to exceed its rated capacity for a short period of time for a set penalty, i.e. price. We demonstrate the effectiveness of these models by testing them on large-scale ISO network models.**

***Index Terms*—Integer programming, power generation dispatch, power system economics, power transmission control, power transmission economics**

Nomenclature

Indices and Sets

g	Generator.
$g(n)$	Set of generators at node n.
i	Flowgate bidding block index.
k	Transmission element (line or transformer).
$k(n,.)$	Set of transmission assets with n as the 'to' node.
$k(.,n)$	Set of transmission assets with n as the 'from' node.
m, n	Nodes.

Parameters

B_k	Electrical susceptance of transmission element k.
c_g	Cost of production from generator g at node n.
c_i	Cost associated with the i^{th} block of the flowgate bidding function.
d_n	Real power load at node n.
J	Number of open transmission elements.
M_k	Big M value for transmission element k.
P_g^{max}	Max capacity of generator g.
P_k^{max}, P_k^{min}	Max and min capacity of transmission element k; typically $P_k^{max} = -P_k^{min}$.
δ_k	Percent of the steady state operating level of transmission element k.
$\theta_n^{max}, \theta_n^{min}$	Max and min voltage angle at node n.

Variables

P_g	Real power supply from generator g at node n.
P_{ik}	Added flowgate capacity for transmission element k from block i.
P_k	Real power flow from node m to n for transmission element k.
z_k	Binary variable for transmission element k (0 open/not in service, 1 closed/in service).
θ_n	Bus voltage angle at node n

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I. Introduction

THE electric transmission network is unique and complex. In practice, the modeling of the network, however, is less so. There are various control mechanisms that have yet to be harnessed in an automatic setting. There is a national push to model the grid in a more sophisticated, smarter way; FERC order 890 calls for better economic operations of the transmission grid. Part of the smart grid concept aims at making better use of the current infrastructure as well as additions to the grid that enable more sophisticated use of the network. In this paper, we focus on two ideas that improve the use of the current infrastructure: just-in-time transmission and flowgate bidding.

Transmission within electrical networks is traditionally characterized as a static system with random outages over which the system operator dispatches generators to minimize cost while ensuring reliability standards are met. However, both formally and informally, system operators can and do change the topology of systems to improve voltage profiles or increase transfer capacity [1]. These decisions are neither automated nor systematic.

Previous work has demonstrated the possibility of substantial savings by implementing the decision to have any transmission element open or closed within the dispatch optimization problem. In [2] O'Neill *et al.* initially presented the concept of a dispatchable network. Fisher *et al.* [3] and Hedman *et al.* [4] applied optimal transmission switching with a Direct Current Optimal Power Flow (DCOPF) formulation to the standard IEEE 118-bus test case, but did not enforce the reliability constraints. However, Hedman *et al.* [5] tested optimal transmission switching with an N-1 DCOPF formulation on the IEEE 118-bus test case and on the RTS 96 test case and demonstrated that savings can be obtained by optimal transmission switching while satisfying N-1 reliability constraints. Hedman *et al.* [6] have also shown that optimal transmission switching can provide savings over multiple periods and can improve the generation unit commitment schedule while satisfying strict reliability constraints.

The reliability requirements for the electric grid create redundancies that can cause higher operating costs. The just-in-time transmission concept allows operators to optimize the network topology for economic gains and whenever there is a disturbance, the transmission can be switched back into service to bring the system back to being N-1 reliable.

Such an operation would require adequate ancillary services and generator ramping capabilities to be able to reach a feasible dispatch solution once the topology is changed after the contingency. Fast detection of the contingency and switching of the lines would increase the ability to maintain reliability. This research identifies potential economic benefits if such a smart grid technology were developed.

With this method, we are not ignoring the importance of reliability, nor are we suggesting dispatching transmission at the expense of reliable network operations. We are examining the potential for automating actions operators currently take, such as implementing Special Protection Schemes (SPSs), and improving network operation by making use of controllable components. With just-in-time transmission, transmission elements that are open in the optimal dispatch of a network may be available to be switched back into the system as needed, as in PJM's SPSs. In cases where this may not be possible, transmission switching can be conducted in conjunction with contingency analysis in order to maintain reliability levels while taking advantage of improved topology, as has been demonstrated by [5]. Therefore, transmission dispatch is not by definition incompatible with reliable operation of the grid.

In fact, transmission switching can be used to improve various issues, including reliability. Transmission switching has been presented in the literature as a control method for problems such as over or under voltage situations, line overloading [7]-[10], loss and cost reduction [11]-[13], system security [14], or a combination of these [15]-[17]. Numerous SPSs address specific instances of switching during emergency conditions. Some SPSs open lines during emergency conditions, demonstrating that it can be beneficial to change the topology during a disturbance.

Flowgate bidding allows a transmission element's thermal, steady-state capacity constraint to be exceeded for a set cost. The premise for the flowgate bidding model is based on the fact that better utilization of transmission is possible by modeling how transmission elements are affected when they operate at levels beyond steady-state limits. There can be a cost associated with operating a line above its steady-state capacity limit; this can be a result of damage to the line or reducing its residual life. Though there is an associated cost with this action, it adds flexibility to the optimization problem and may allow for better generation dispatch solutions. The overall cost of the network, which includes this additional flowgate bidding cost, would be lower overall thereby creating a net savings. If there is not a net savings, the decision to overload the line would not be made. The flowgate bidding model has already been approved by the Federal Energy Regulatory Commission (FERC) and it has been implemented by the Southwest Power Pool (SPP) and the New York Independent System Operator (NYISO).

Section II presents an overview of the Independent System Operator of New England (ISONE) test cases used in this paper along with the software description. To assess the potential economic benefits of the just-in-time transmission concept, we used the optimal transmission switching formulation, which is presented in Section III. Section IV presents the results for this optimization problem for two different ISONE networks. Section V then provides the discussion on flowgate bidding. Section VI presents possible topics for future work and Section VII concludes this paper.

II. ISONE Models and Software Description

The base test case used in this paper is referred to as the summer peak test case, which ISONE uses for economic studies. The second network model was used by ISONE to determine import levels into Connecticut (CT). Each ISONE network model contains the ISONE area, the NYISO area, the Nova Scotia (NS) area, and the New Brunswick (NB) area. Each network model has over 4,500 buses. The base model, i.e. without transmission switching, is a DCOPF problem, which is a linear programming (LP) problem.

Table I lists information regarding the transmission elements, the generators, and the load for the summer peak test case. The Connecticut import test case is similar in size to the summer peak test case; it has 400 fewer buses, 5% higher load level, and 550 fewer transmission elements. Many generators have a zero production cost as these units either have a zero cost like hydro or the generators are outside the ISONE area. The generators that have a zero production cost represent 63% of the generation capacity and 74% of all generators.

TABLE I
ISONE SUMMER PEAK TEST CASE

		Capacity (MW)		
	No.	**Total**	**Min**	**Max**
Transmission Elements	6652	2,663k	2	9,999
Generators	689	69,078	0.07	1,500
Load	2209	57,888	-19.06	551

Table II lists the number of variables and constraints for the summer peak test case for the LP base model, i.e. all transmission elements are in service and treated as fixed assets, and for the mixed integer programming (MIP) problem when transmission switching is introduced into the DCOPF. The model is written in AMPL and we use the CPLEX solver. Before the problem is sent to CPLEX, AMPL performs a presolve routine that eliminates redundant and unnecessary variables and constraints. The residual variables and constraints are listed in Table II and are denoted by "post presolve." The results presented in this paper reflect one hour.

The CPU specifications are: duo-core processor, 3.4GHz, and 1GB ram.

TABLE II
ISONE SUMMER PEAK TEST CASE: VARIABLES AND CONSTRAINTS

ISONE Summer Peak Test Case	LP	MIP
Total Variables:	12,237	18,889
Binary Variables:	0	6,652
Total Linear Constraints:	23,786	37,090
Upper or Lower Bound Constraints:	12,237	18,889
Total Variables (Post Presolve):	11,101	16,701
Binary Variables (Post Presolve):	0	5,600
Linear Constraints (Post Presolve):	17,063	27,441

III. PROBLEM FORMULATION

The just-in-time transmission optimization problem incorporates additional flexibility than the optimal transmission switching with contingency analysis problem, see [5], by acknowledging in the day-ahead optimization problem the operator's ability to implement a corrective switching action after a contingency occurs, which is similar to certain SPSs that exist today. In the day-ahead setting, the operator would co-optimize the generation and network topology for each steady-state period but would also simultaneously determine the required corrective switching actions to take if a specific contingency were to occur.

Capturing this operational flexibility, the use of transmission switching as a corrective mechanism when there is a contingency, allows the operator to improve economic efficiency of the system for steady-state operations. The operator can open lines to reduce network redundancies that cause dispatch inefficiencies for steady-state operations while knowing that such temporarily out-of-service lines can be switched back into service, if needed, in order to bring the system back to an N-1 reliable state.

To assess the potential economic benefits of the just-in-time transmission concept on a large-scale system, we test the optimal transmission switching problem on two ISONE test cases. This problem is formulated as a MIP. The use of MIP within the electric industry is growing. PJM has switched from Lagrangian Relaxation (LR) to a MIP approach for their generation unit commitment software [18] and for their real-time market look-ahead [1]. These changes are estimated to save PJM over 150 million dollars per year ([1] and [18]). Furthermore, most US ISOs are testing and planning to switch to MIP in the near future [19].

The optimal transmission switching DCOPF formulation has been presented and discussed in [3] and [4]. The DCOPF, which is an LP, is a commonly used linear approximation of the Alternating Current Optimal Power Flow (ACOPF). The objective of the optimization problem is to minimize total cost (1). Since the demand is perfectly inelastic, minimizing the total cost is the same as maximizing the total market surplus. This objective is valid for systems where generation dispatch is a centralized process in which operating costs are known. For systems where the dispatch is determined by a centralized operator who receives bids, we optimize the bid surplus. In further discussion, we assume that bids are marginal costs.

The constraints represent the traditional power flow constraints that follow Kirchhoff's Laws, except for the modifications made to incorporate transmission switching. This is a lossless model, which allows us to use only one variable to represent a transmission element's power flow, which is represented by P_k. Therefore, the node balance constraints, (3), account for the set of P_k variables connected to bus n, i.e. $k(n,.)$, which are injections, the set of P_k variables connected from bus n, i.e. $k(.,n)$, which are withdrawals, and the supply injections by the set of generators at bus n, i.e. $g(n)$. If this were a lossy model, losses may increase or decrease, see [11] and [13], as a result of transmission switching. The objective is to minimize the total cost so even if losses increase, transmission switching can still be of value by decreasing the total cost. Constraints (4), (5a), and (5b) are modified to incorporate the decision to have a transmission element closed or open in the network. Injections into a bus are positive (generator supply, power flow to bus n) and withdrawals are negative (load, power flow from bus m)

$$\text{Minimize: } \sum_g c_g P_g \tag{1}$$

s.t.

$$\theta^{\min} \le \theta_n \le \theta^{\max}, \forall n \tag{2}$$

$$\sum_{k(n,.)} P_k - \sum_{k(.,n)} P_k + \sum_{g(n)} P_g = d_n, \forall n \tag{3}$$

$$P_k^{\min} z_k \le P_k \le P_k^{\max} z_k, \forall k \tag{4}$$

$$B_k(\theta_n - \theta_m) - P_k + (1 - z_k) M_k \ge 0, \forall k \tag{5a}$$

$$B_k(\theta_n - \theta_m) - P_k - (1 - z_k) M_k \le 0, \forall k \tag{5b}$$

$$0 \le P_g \le P_g^{\max}, \forall g\,. \tag{6}$$

Constraints (5a) and (5b) are modified in order to ensure that if a transmission element is opened, these constraints are satisfied no matter what the values are for the corresponding bus angles. In (5a) and (5b), M_k is often called the "big M" value where M_k is large enough to make the constraint nonbinding. M_k must be a large number greater than or equal to $|B_k(\theta^{max} - \theta^{min})|$. The chosen min and max bus angle values are ±0.6 radians. It is computationally conducive to have M_k be as small as possible, which is $|B_k(\theta^{max} - \theta^{min})| = 1.2|B_k|$. We formulate the bus angle constraints by (2) instead of a bus angle difference formulation since (2) places a bound on M_k, which is computationally helpful, and because bus angle difference constraints are subsumed by line capacity constraints within DCOPF formulations.

A similar MIP model, see [20], is used for transmission expansion in which they formulate a shortest path problem to determine the minimum M_k value. Within their model, all original lines remain closed thereby preserving all original existing paths between any two buses. With our optimal transmission switching model, the original topology can be altered by the opening of lines. Using this shortest path problem to determine the minimum M_k value for our model would require M_k to be a variable rather than a parameter. Likewise, the shortest path problem would have to be resolved for each possible network configuration. As a result, it is conducive to model the bus angle constraints by (2) as then there is no need for this shortest path problem. Based on (2), it is then possible to define M_k as we previously stated.

There may be costs associated with the act of switching lines. The formulation above can be easily modified to incorporate a switching cost; it does not include a switching cost at this time since we do not have such cost information. For further discussion on optimal transmission switching, please refer to [3]-[6].

IV. ISONE Results and Analysis

A. Transmission Switching DCOPF Results

As shown previously by Table II, this MIP has over 6,600 binary variables. With such a large and complex mixed integer program, the branch and bound tree reaches a size that exhausts the memory of the computer when trying to solve for the optimal solution. However, our motivation is not to prove optimality. Operators do not prove optimality today but rather find the best feasible solution within their available timeframe. Our motivation is to show that there can be substantial savings obtained by transmission switching with an ISO network if the smart grid has the appropriate advanced contingency detection and switching technology. We therefore use heuristic techniques to find better feasible solutions and study the impacts on market participants.

We first restricted the number of transmission lines that can be opened by adding an equality constraint with J representing the number of lines opened. The ISONE summer peak test case was first tested for a single peak hour. Before any lines are allowed to be opened, the DCOPF optimal solution has a generation cost of \$523k/hr for the original network topology; with all lines forced to being in service, this problem is a linear program. For $J=1$, the solution time to find the single best line to open took two hours and provided a 4% savings. The $J=2$ solution took 58 hours, provided a 5.5% savings, and had a 3.9% optimality gap. The $J=4$ solution took 82 hours, provided a 6% savings, and had an 8.9% optimality gap.

Further information is provided in Figure 1 along with the impact on generation rent, generation revenue, congestion rent, and load payment. The values are presented as percentages of the LP base DCOPF solution, which is the $J=0$ solution. Since not all of the solutions reached optimality, Figure 1 also lists the greatest lower bound for each corresponding problem. Figure 2 shows the computation statistics along with the optimality gaps. All solutions have a reduction in congestion rent, load payment, and generation rent; however, the only guaranteed result is that the generation cost will not increase.

There is no guarantee that there will be more savings from optimizing a heavily congested network as compared to networks that are not as heavily congested. It is possible for a solution that increases the market surplus by transmission dispatch to have more congestion rent than the solution for the original topology, [4]. It is therefore not possible to guarantee that other ISO networks that are more or less heavily congested than ISONE will obtain more or less savings. Further discussion on the impacts of transmission switching can be found in [3]-[6].

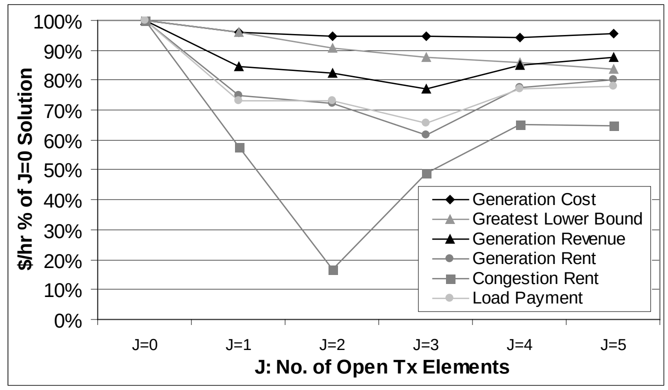

Fig. 1. ISONE Summer Peak Test Case Results

One interesting result is that a few LMPs are above \$1000/MWh. Such a high LMP seems to be extreme but further analysis showed that this is based on enforcing thermal constraints for all of the lines and transformers. All of the high LMPs come from lower voltage buses in tightly constrained areas where an additional MW results in a large redispatch of the system. When thermal constraints of the lower voltage lines and transformers are not enforced, as ISONE does when using this model, the high LMPs disappear. Section IV.D presents results from a study where the capacity constraints for the lower voltage transmission elements are not enforced.

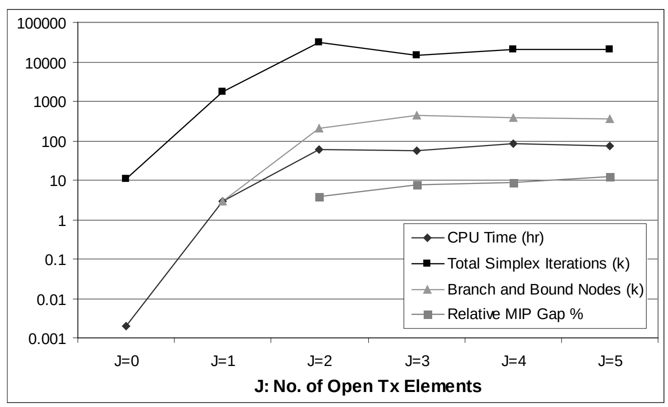

Fig. 2. ISONE Summer Peak Test Case Computational Statistics

B. Addressing the Complexity of a MIP Transmission Switching DCOPF Model

The previous section presented results where optimality was not proven even when allowing only a few transmission elements to be opened. Finding the single best transmission element to open took roughly two hours; after 50 hours, optimality was not achieved when trying to find the two best elements to open for the summer peak test case.

We address this issue with two simple heuristic methods; these methods do not guarantee optimality but they find good feasible solutions fast. First, we used the iterative approach to improve the solution time. Starting with no lines open, in each iteration, we find the single best line to open and then force it to be open in all subsequent iterations; the process is then repeated. When we implement the iterative approach, we also apply partitioning during each iteration. Partitioning takes the set of possible solutions and divides it into multiple subsets that are mutually exclusive and collectively exhaustive. Each subset contains a different set of possible network topologies for that iteration. Finally, the overall optimal for that iteration is determined by comparing the optimal solutions from all subsets. These partitioned sets can be solved in parallel, i.e. solve these subsets at the same time on various computers; however, we did not implement parallel computing so the solution time reflects the aggregate time to run all subsets for all iterations.

We used this technique on the summer peak network. Using the partitioning technique worked extremely well for this particular MIP problem. Without using this partitioning technique, the total solution time for the solution in Table III would be 42 hours; with the partitioning technique, we were able to reduce the solution time down to 6.3 hours. Using this heuristic technique we found 20 elements to open faster than the $J=2$ solutions in Section IV.A with more savings as well. Results are displayed in Table III for 20 iterations. The base generation cost was $523k/hr, which reflects the base LP DCOPF solution with no lines opened. With a 12% savings, transmission switching has saved over $60k/hr. Since this method does not guarantee optimality, the true optimal may provide much more savings. Of the 20 elements that were opened, 15 were lines of at least 115kV; the most common lines opened, seven in total, were 345kV lines. The lowest voltage lines opened were 69kV and there were three transformers that were opened. There was a 69kV parallel line and an 115kV parallel line that were opened.

TABLE III
SUMMER PEAK BASE TEST CASE – BEST FEASIBLE SOLUTION

Percent of Original Dispatch Cost	0.881
Savings ($/hr)	62k
CPU Time (hr)	6.3

For the solution in Table IV, we used a different heuristic technique. This second approach uses past information to improve the solution and solution time, which we call the intelligent learning heuristic. The intelligent learning technique is meant to reflect practical methods that operators can use to improve the solution based on past information. Specifically, operators can consider past transmission switching solutions and use that information to focus on key transmission lines in future studies. The transmission switching solutions will vary as network conditions vary but it is possible that there are key lines that are opened from time to time. We therefore restricted which lines can be considered for switching in this next study, which is on the Connecticut import test case; the candidate lines, 51 in total, were chosen from the various solutions obtained from the other network model, the summer peak test case. The DCOPF solution with the topology unchanged, which is an LP, has a $474k/hr cost. The best found feasible solution provided a 13% savings in 3.2 hours; since this method cannot guarantee optimality, the true optimal may provide much more savings. The results are in Table IV.

TABLE IV
CONNECTICUT IMPORT BASE TEST CASE – BEST FEASIBLE SOLUTION

Percent of Original Dispatch Cost	0.87
Savings ($/hr)	61k
CPU Time (hr)	3.2

C. Fixed Net Imports

The ISONE model does not contain generator cost information for generators that are outside of the ISONE region. The network model includes the ISONE, NYISO, NB, and NS areas. ISONE specified the scheduled net imports for the areas that are connected to the ISONE region. This sensitivity study analyzes the impact of fixing net imports for each area by fixing these outside generators. For the summer peak test case, an optimal solution was found for the LP base test case with no transmission elements opened that provided 300MW of export from ISONE. This solution is used as the LP base solution for this summer peak test case sensitivity study; it has a generation cost of $660k/hr. The generators outside of ISONE are then fixed based on this LP DCOPF solution for the transmission switching sensitivity study. The same sensitivity study was performed for the Connecticut import test case as well; the LP base solution, i.e. no transmission elements opened, has a generation cost of $485k/hr. The results for both studies are in Table V.

TABLE V
SENSITIVITY STUDY – FIXED NET IMPORTS

	Summer Peak	CT Import
Percent of LP Base Solution	88.9%	94.1%
Savings $/hr	73k	28k

Fixing the generators outside ISONE for the summer peak test case did not have much of an impact on the overall savings as shown by the results from Table III and Table V. For the CT import test case, fixing the generators outside ISONE provided a lower percent savings as compared to the case when the generators are not fixed. The best found solution for this study has a 6% savings as compared to the 13% savings in Section IV.B when the outside generators are not fixed. It appears as though the outside generators may have influenced the results in Section IV.B; however, this is not known for certain as neither problem has been solved to optimality.

D. Fixed Net Imports and Capacity Constraints for Transmission Elements Below 115kV Not Enforced

In this section as well as the next section, we present sensitivity studies where we do not enforce the capacity constraints for lower voltage transmission lines, i.e. lines below 115kV. These two sensitivity studies are included as a way to build insight as to what may or may not cause such economics savings. In particular, the results demonstrate that the potential transmission switching savings are not purely a result of alleviating congestion in the lower voltage network.[1]

For this sensitivity study, the net imports are fixed as was done in the previous section. For the summer peak test case, the transmission switching savings are not as significant in this study as previous studies, though the savings are still substantial at 5%. For the CT import test case, there is a 9.3% savings for this study; this is higher than the savings presented in Section IV.C where all lines' capacity limits were enforced.

[1] When conducting certain economic studies, ISOs may not enforce the capacity constraints for lower voltage transmission lines; this is done at times to improve solution time of large studies, e.g. transmission expansion, if the accuracy of the results is maintained. In particular, ISONE did not enforced capacity constraints for lines below 115kV when using these test cases.

E. 70% of Peak Load

This sensitivity has the net imports fixed, the capacity constraints are not enforced for transmission elements below 115kV, and the load is reduced by 30% to analyze the affect of an off-peak hour. It follows the same setup as in Section IV.D except that the load has been reduced by 30% and the net export level for ISONE has been reduced by 30%. This sensitivity was tested on the Connecticut import test case.

The LP DCOPF solution for the original network topology is $132k/hr. The best found feasible solution provided a 7.4% savings. Note that these percent savings are not far off from the 9% savings presented in Section IV.D for the Connecticut import test case. Further investigation may produce solutions with similar savings found in Section IV.D.

The two ISONE models presented in this paper differ in load by 5% but both produce substantial savings. This factor along with the sensitivity results within this section suggest that it is possible to obtain substantial savings from transmission switching for various load levels. We do not make the claim that this is the case in general, only that these particular results show the possibility of substantial savings at varying load levels for a large-scale ISO network.

V. Flowgate Bidding

A. Overview

Flowgate bidding is defined as allowing a transmission line's flow to exceed its steady-state rated capacity for a set price. This operation is of interest since there are situations where there can be a large gain by temporarily allowing a line to be operated beyond steady-state capacity. There can be situations where the difference between being required to start up a generator or not is based on the ability to temporarily operate a line beyond steady-state capacity. The damage to the line is minimal, if at all, but the benefit is large enough to overcompensate for any costs associated with operating the line beyond steady-state capacity. The cost of temporarily operating a line beyond steady-state capacity is a reflection of reducing the life of the line. In situations where the dual variable, i.e. shadow price, on the capacity constraint is higher than the cost to operate the line beyond steady-state capacity, the optimal decision is to temporarily operate the line beyond steady-state capacity as long as reliability standards are maintained.

Operating a conductor beyond its steady-state capacity can cause creep, annealing, reduce its strength and therefore reduce its residual life, and it can impact the characteristics of the line as well. In [21] and [22], Morgan examines the loss of tensile strength from elevated temperatures and due to annealing respectively. In [23], Harvey develops a model to estimate the remaining strength in a line due to elevated temperature operations. In [24], Havard *et al.* attempts to predict the residual life of an aged ACSR conductor. In [25], Harvey and Larson examine impacts on the sag of a conductor due to operating the conductor beyond steady-state capacity. Additional work on how conductors can be affected by elevated temperature operations and the associated costs of such an action is needed.

There have been many papers that discuss dynamic thermal line ratings. There is also research into developing adaptive emergency ratings [26], which adjusts the rating based on the time interval the line operates at the defined level and based on the initial temperature. Flowgate bidding is different than these methods that determine a rating such that there is no damage to the line; flowgate bidding has the objective to operate the line at a level that may incur costs due to reducing its lifecycle but these costs are always less than the benefit gained by choosing to perform such an operation.

The flowgate bidding model presented in this paper has been approved by the Federal Energy Regulatory Commission (FERC), which approves reliability standards and monitors compliance. The Southwest Power Pool (SPP) [27] places a $2000/MWh price and the New York Independent System Operator (NYISO) [28] has a $4000/MWh price on operating flowgates beyond steady-state capacity. These high prices are a result of being overly cautious to maintain reliability. Statistics from the NYISO website indicates that the $4000/MWh price is incurred about 0.5 percent of the time.

A transmission line's sag will increase when the flow increases due to additional heating. It is not permissible to operate a line to a point where there can be a fault due to excessive sagging. We are not suggesting that this requirement be ignored. Each line has an emergency rating that it is able to operate at without causing excessive sagging that would cause a fault. Such a rating can be used to place an upper bound on how much the line can temporarily operate beyond its steady-state capacity due to the flowgate bidding.

Line ratings can be set based on reliability standards, such as the sagging example previously described. Ratings are also placed on transmission lines so that the line will function as expected over its chosen lifecycle. The flowgate bidding model would account for both of these situations by properly identifying the incremental capacity, δ_k, for the line, which is used in (12). This parameter is used to ensure that operation beyond steady-state capacity does not result in a violation of reliability standards. Then, it is possible to make the optimal decision regarding whether to temporarily operate the line beyond steady-state capacity.

The cost of operating the line beyond steady-state capacity would depend on the current state of the transmission element, the duration of time the line is overload, the overload level, and the immediate past usage of the transmission element. Since the strength of the line would deteriorate over time, the cost to operate the line beyond its steady-state capacity would increase over time. Likewise, the damage may be more extensive when the transmission element has been operated beyond steady-state capacity in recent hours as there is a time lag with the temperature of the transmission element since it does not immediately cool down to normal operating temperatures once the operation beyond steady-state capacity stops. Incorporating a cumulative cost function is important in order to ensure the loading of the transmission element returns to its steady state operating level before reliability standards are impacted.

SPP and NYISO place a high, fixed price on operating lines beyond their steady-state capacities so that the operation beyond the steady-state capacity will be short lived and the high price drives the operation back to steady state before there is any severe damage or impact on reliability. Modeling the thermal dynamics as previously discussed would achieve the same by having the cost increase in order to force the transmission element's power flow back to its steady state operating limit. The difference would be that the price is more reflective of the true costs of operating the line beyond its steady-state capacity. These thermal dynamic characteristics are not captured within this model as this model analyzes just one period. We are currently working on modeling such thermal dynamics and associated costs of operating a line beyond its steady-state capacity.

B. Flowgate Bidding Formulation

Flowgate bidding adds flexibility to the optimization problem by allowing the transmission element's flow to exceed the steady-state operating level. However, there is a cost associated with exceeding the steady-state operating level as this can cause damage to the transmission element and/or reduce the lifespan of the element. The objective is to minimize total cost, which includes the generation cost and the cost accrued by exceeding the steady-state operating level of the chosen transmission elements. Thus, the purpose is to consider the tradeoffs between savings from a better generation dispatch by allowing a transmission element to exceed its steady-state operating level and the costs associated with this action. This problem is an LP like the DCOPF.

The formulation uses an i^{th} step flowgate bidding function representing the quantity the transmission element exceeds its steady state operating level and the associated cost. P_{ik} reflects the added flowgate capacity for transmission element k from the i^{th} block and the cost for each block is represented by c_i

$$\text{Minimize: } \sum_g c_g P_g + \sum_{i,k} c_i P_{ik} \tag{7}$$

s.t.

$$\sum_{k(n,.)} P_k - \sum_{k(.,k)} P_k + \sum_{g(n)} P_g = d_n, \forall n \tag{8}$$

$$P_k + \sum_i P_{ik} \geq P_k^{\min}, \forall k \tag{9a}$$

$$P_k - \sum_i P_{ik} \leq P_k^{\max}, \forall k \tag{9b}$$

$$B_k(\theta_n - \theta_m) - P_k = 0, \ \forall k \tag{10}$$

$$0 \leq P_g \leq P_g^{\max}, \ \forall g \tag{11}$$

$$0 \leq P_{ik} \leq \delta_k P_k^{\max}, \forall k. \tag{12}$$

The flowgate marginal price (FMP), which is the shadow price on the capacity constraints (9a) and (9b), indicates whether it is beneficial to operate the transmission element beyond steady-state capacity. If the FMP is higher than the price, c_i, to operate the transmission element beyond steady-state capacity, then the objective will decrease by a larger factor than the cost associated with operating the transmission element beyond steady-state capacity. Thus, if the element is operated beyond steady-state capacity, the element will operate at a level such that the FMP matches the cost of operating the transmission element beyond its steady-state capacity, c_i, or until (12) is binding.

Modifying the problem in this way increases the feasible region such that the original feasible region is a subset of the new feasible region. This guarantees that the new solution is at least as good as the original. If the savings involved in allowing a transmission element to exceed its steady state operating level do not outweigh the costs, the action will not take place; only when there are net savings will the transmission element's power flow temporarily exceed its steady state rating, thereby creating a net gain in total surplus.

C. Flowgate Bidding Results and Analysis

In this section, we examine the summer peak test case. These prices are set high as the true cost of operating a transmission element beyond its steady-state capacity is not well understood. Most lines can be operated beyond steady-state capacity during emergency conditions up to 20% and, at times, up to 30%. We are not advocating that these levels can be implemented or that the costs associated with the operation beyond steady-state capacity is accurate. Rather, the examples below demonstrate the possible savings for a range of possible conditions. We first start with the prices that are in place in SPP and NYISO. For this example, we assume that the maximum allowable levels that the lines can operate beyond their steady-state capacities are 10% and 20%. The results are the same if we increase the level above 20%.

The savings obtained is the difference between the base solution without flowgate bidding, \$523,616/hr, and the flowgate bidding solution; the results are displayed in Table VI and Table VII. The new total costs are listed in the tables. The new total cost equals the sum of the new generation cost and the flowgate cost.

TABLE VI
FLOWGATE BIDDING RESULTS – NYISO COST

$C_1 = C_2 = C_3 =$ \$4,000/MWh		
Max Percent Above Steady-State Capacity	**10%**	**20%**
Savings	6,466	6,655
New Total Cost	517,151	516,962
New Generation Cost	510,747	508,943
Total Cost Savings Percent	1.23	1.27
Flowgate Bid Cost	6,404	8,019

TABLE VII
FLOWGATE BIDDING RESULTS – SPP COST

$C_1 = C_2 = C_3 =$ \$2,000/MWh		
Max Percent Above Steady-State Capacity	**10%**	**20%**
Savings	12,023	12,478
New Total Cost	511,593	511,139
New Generation Cost	504,608	503,105
Total Cost Savings Percent	2.30	2.38
Flowgate Bid Cost	6,985	8,034

The testing for the above results had the same price level for any operation beyond steady-state capacity. For the following results, we use a step function that follows the model formulation in Section IV.B. There are three steps, i.e. $i=1, 2, 3$, each with a different price and each step has the same available quantity; $\delta_k=10\%$ of the line's steady-state rating. There are higher costs for the latter steps in order to reflect the fact that the impact on the line is not linear; as the operation beyond steady-state capacity level increases, the impact to the line increases and, thus, the costs increase.

For Table VIII, we set the prices at \$500/MWh, \$750/MWh, and \$1,000/MWh. For the 10% column, the line's flow can be up to 10% beyond its steady-state rating at a price of \$500/MWh. For the 20% column, the line can be operated up to 20% at a price of \$500/MWh for the first 10% and \$750/MWh for the second 10% block. We tested the network with the maximum operation level beyond steady-state capacity set at 30%. However, the results were the same as the 20% level results meaning that it was not optimal to operate any line beyond 20% of its steady-state capacity given the chosen costs. Another study was conducted with costs set at \$100/MWh, \$150/MWh, and \$200/MWh; the results are in Table IX.

TABLE VIII
FLOWGATE BIDDING RESULTS – INCREMENTAL COSTS

C_1 = \$500/MWh, C_2 = \$750/MWh, C_3 = \$1,000/MWh		
Max Percent Above Steady-State Capacity	**10%**	**20%**
Savings	18,288	18,961
New Total Cost	505,328	504,655
New Generation Cost	501,793	502,249
Total Cost Savings Percent	3.49	3.62
Flowgate Cost	3,535	2,406

TABLE IX
FLOWGATE BIDDING RESULTS – INCREMENTAL COSTS EXAMPLE 2

C_1 = \$100/MWh, C_2 = \$150/MWh, C_3 = \$200/MWh			
Max Percent Above Steady-State Capacity	**10%**	**20%**	**30%**
Savings	26,611	30,184	31,825
New Total Cost	497,006	493,432	491,792
New Generation Cost	490,003	483,579	480,279
Total Cost Savings Percent	5.08	5.76	6.08
Flowgate Cost	7,002	9,853	11,512

One interesting result comes from Table VIII. Notice that the flowgate cost is higher with the maximum level set at 10% as compared to the 20% level's flowgate cost. Essentially, this means that there was a line that was operated beyond 10% of its steady-state capacity in the 20% case. As a result, the flowgate marginal prices on other lines were lower in the 20% case such that the lines were operated at levels below the chosen operational levels within the 10% case. By not being able to operate a line beyond its steady-state capacity as much as desired within the 10% case, other lines were also operated beyond their steady-state capacities to the point that the total cost of operating beyond steady-state capacity is higher than in the 20% case. This demonstrates the possibility that operating a few lines a bit more beyond their steady-state capacities as opposed to operating more lines to a lesser extent beyond their steady-state capacities can be less expensive in regards to both the flowgate costs and the total cost.

Our motivation is to provide the concept of this model and to show the possible savings. We are not advocating for these exact costs or these exact operational levels. Additional research is needed regarding the actual costs of operating lines beyond their steady-state capacities; determining the cost associated with overloading the line requires knowing the state of the line, i.e. its current strength and residual life, the damage, and then the reduction in its residual life as a result of the overloading.

VI. DISCUSSION AND FUTURE WORK

A. Just-in-time Transmission

The next steps would be to further investigate what it will take to develop an advanced switching technology and an advanced detection technology that would enable automatic switching when there is a specific disturbance. If such technologies are not present, optimal transmission switching can still be used while ensuring reliability standards. Additional future research should include analyzing the impacts on transient stability due to the network switching and improving the computational performance.

As a result of increased switching actions further research is needed as to the effect on breakers, whether there will be additional required maintenance, and whether more advanced, new breakers would be required to be installed. Any additional costs should be considered in future research. However, any such additional costs are likely to be minor in comparison to the substantial potential economic savings that have been demonstrated in this paper and, thus, such costs are unlikely to significantly change the results presented in this paper.

In this paper we have examined transmission switching with an AC approximate formulation, the DCOPF model; future research should investigate transmission switching with an AC setting as well. With today's optimization software, solving a large-scale mixed integer non-linear program is very difficult. For example, operators today use the DCOPF formulation with unit commitment as opposed to an ACOPF; with the integer based variables fixed, the solution is then used as an initial solution that is fed into an ACOPF solver to obtain the best feasible AC solution possible. It is likely that a similar approach would be taken if transmission switching is to be implemented. By using such an approach, there is no guarantee that an AC feasible solution will be obtained when using an AC approximate formulation to produce an initial solution and, thus, future research is needed to investigate this concern.

The grid of the future will be required to handle additional complexities and issues; one example of this fact is increased wind energy penetration. The two concepts presented in this paper aim at developing a smarter, more flexible grid. Future research should also consider how these concepts may facilitate wind energy penetration.

B. Flowgate Bidding

Further research should examine the marginal impact on operating lines beyond their steady-state capacities, including a method to determine the safe operating level given the current state of the line and the cost associated with operating the line beyond its steady-state capacity. Without this additional research, there is the tendency to take a worst case approach. In part, this is the reason behind the choice in costs for the SPP and the NYISO.

This testing was done with a DCOPF model, which ignores reactive power. However, this model can be modified to better approximate the actual line flows by derating the line capacities to account for the fact that there will be a reactive power flow on the lines. This can be addressed in future work.

This flowgate bidding model does not incorporate N-1 standards. Contingency constraints can be easily built into future work. The model also does not include generation unit commitment. One possible benefit of flowgate bidding is that there can be situations where you temporarily operate a line beyond steady-state capacity instead of starting up a peak generating unit.

Transmission owners may not be willing to risk their equipment and allow their lines to be overloaded. The market surplus will not decrease with this model and will most likely increase. If transmission owners are against this concept, they will be leaving money on the table instead of coming to an agreement. However, developing an appropriate compensation scheme is not easy and could be a future research topic.

Flowgate bidding could also be of particular interest for wind farms. Wind farms typically do not reach a power output that is close to their capacity. There is then the question as to what is the appropriate line capacity that should be connected to the wind farm. Building a line with a capacity that matches the wind farm's total capacity may result in additional transmission line costs that may not be necessary. If the line has less capacity than the wind farm's capacity, there can be spillage. There is the question as to what is the optimal transmission line capacity for a radial line to a wind farm. By incorporating the ability to temporarily operate lines beyond their steady-state capacities, the flowgate bidding model could provide savings in transmission line costs.

VII. Conclusion

There is a national push to improve the electric grid and there are a variety of ways in which we can improve the grid. The true grid of the future should include advanced technology, be more flexible, and operate in new ways. Novel ideas that change how we view the grid are necessary. In this paper, we have proposed that the way in which we view transmission assets should change and we have presented two concepts for the smart grid: just-in-time transmission and flowgate bidding. Though reliability standards were not enforced in this research, there has been past research on transmission switching with N-1 reliability constraints, see [5] and [6]. With adequate ancillary services, ramping capabilities, and an advanced switching technology, reliability standards can still be met with the methods presented in this paper. Further research is required for these methods to be practically implemented; this paper is the start to that process and to developing the grid of the future.

The full development of just-in-time transmission depends on the development of an advanced switching technology and an advanced detection technology so that the network topology can be changed within a specified time when there is a disturbance. With such a technology in place, the topology can be optimized and substantial savings can be obtained, as has been demonstrated in this paper on a large-scale ISO network. Even if this technology is not available, savings from co-optimizing the network topology and generation with reliability constraints has been shown to be possible in past research and it remains an important research topic.

The flowgate bidding model is very similar to the typical DCOPF formulation; the necessary changes are easy to make and are easily understood. With a call to create the smart electric grid, the motivation here is a discussion on ways in which we can enhance the electric grid with smarter modeling and more advanced technology. Such a technology and knowledge about transmission lines and the cost of operating a line beyond its steady-state capacity do not exist today; however, these results are informative to show that this is a topic worthy of further research based on the possible savings. This research is necessary to evaluate these proposed changes to the electric grid in order to truly obtain a smarter grid.

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