Transmission Unit Commitment for Optimal Dispatch – Sensitivity Analysis and Extensions

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***Abstract*--In this paper, we continue to analyze optimal dispatch of generation and transmission topology to meet load as a mixed integer program (MIP) with binary variables representing the state of the transmission line. Previous research showed a 25% savings by dispatching the IEEE 118 Bus system. This paper is an extension of that work. It presents how changing the topology impacts nodal prices, load payment, generation revenues, cost, and rents, congestion rents, and flowgate prices. Results indicate that choosing the optimal topology typically results in lower load payments and higher generation rents for this network. Computational issues are also discussed.**

***Index Terms*—Mixed integer programming, Power generation dispatch, Power system economics, Power transmission control, Power transmission economics**

I. Nomenclature

Indices

n, m: nodes

k: any asset – line, generator, load

Variables

θ_n: voltage angle at node n

P_{nk}: real power flow from asset k to node n.

z_k: binary variable indicating whether transmission line k is uncommitted ($z_k = 0$), or committed ($z_k = 1$)

TC_J: Total system cost with J uncommitted lines

Parameters

P_k^{max}, P_k^{min}: maximum and minimum capacity of line k

θ_n^{max}, θ_n^{min}: maximum and minimum voltage angle at node n

c_{nk}: cost of production from asset k at node n

B_k: electrical susceptance of line k

J: number of open transmission lines

II. Introduction

Transmission is traditionally characterized as a static system with random outages over which the system operator dispatches generators to minimize cost. However, it is acknowledged, both formally and informally, that system operators can, and do, change the topology of systems to improve voltage profiles or increase transfer capacity.[1] These decisions are made at the discretion of the operators, rather than in an automated or systematic way. The concept of transmission dispatch was introduced by O'Neill et al. [1] in a market context, in which the dynamic operation and compensation of transmission lines is examined. Transmission dispatch was formulated in [2] and tested on a standard engineering test case. In this paper we examine some of the economic impacts and other sensitivities of the formulation and network from [2].

We formulate the problem as a mixed-integer linear program (MIP), based on the traditional DC optimal power flow (DCOPF) used to dispatch generators to meet load in an efficient manner. We then use this formulation to examine the potential for improving generation dispatches by optimizing transmission topology for a well known IEEE test system.

We do not ignore the importance of reliability, nor are we suggesting dispatching transmission at the expense of reliable network operations. We are simply 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. Lines 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 unit commitment can be conducted in conjunction with contingency analysis in order to maintain reliability levels while taking advantage of improved topology. However reliability is maintained, transmission dispatch is not by definition incompatible with reliable operation of the grid.

The paper is organized as follows. Section III. presents the MIP formulation for the transmission unit commitment problem. Section IV. provides the main results and analysis. Section V. discusses the computational statistics. Section VI. covers sensitivity studies and the section also discusses issues regarding practical implementation of this model. Section VII. contains a brief discussion of policy implications, Section VIII discusses future work, and Section IX. concludes this paper.

III. MIP Formulation

This unit commitment problem is the same as in [2]. Generator costs are minimized, subject to physical constraints of the system and Kirchhoff's laws governing power flow. The chosen min and max bus angle values are ±0.6 radians. M_k, listed in (4a) and (4b), is referred to as the "big M" value. z_k is the binary variable representing the state of the transmission line. When the binary variable z_k is one, the value of M_k does not matter; when the binary variable is zero, the value of M_k is used to force the line flow P_{nk} to be zero in order to satisfy (4a) and (4b). In order for this to work, M_k must be a large number greater than or equal to $B_k\left(\theta_n^{\max} - \theta_m^{\min}\right)$. Equation (5) specifies the number of open

[1] Personal communication with Andy Ott, Vice President PJM.

lines in the altered topology. We are not advocating introducing (5) to solve practical problems; this constraint is only used to gain understanding about the effects of changing the network topology for various solutions. To solve the transmission dispatch problem to optimality, (5) would not be present. The formulation below is a basic direct current optimal power flow (DCOPF) problem along with the transmission unit commitment formulation. Variable admittance devices, such as phase shifters, are not modeled within this study and transformers are modeled as transmission lines.

Minimize: $TC_J = \sum_k c_{nk} P_{nk}$

s.t.:

(1) $\theta_n^{\min} \le \theta_n \le \theta_n^{\max}$ $\forall$ Buses

(2a) $P_{nk}^{\min} \le P_{nk} \le P_{nk}^{\max}$ $\forall$ Committed Assets

(2b) $P_{nk}^{\min} z_k \le P_{nk} \le P_{nk}^{\max} z_k$ $\forall$ Committable Assets

(3) $\sum_k P_{nk} = 0$ $\forall$ Nodes

(4a) $B_k(\theta_n - \theta_m) - P_{nk} + (1 - z_k) M_k \ge 0$ $\forall$ Committable Lines

(4b) $B_k(\theta_n - \theta_m) - P_{nk} - (1 - z_k) M_k \le 0$ $\forall$ Committable Lines

(5) $\sum_k (1 - z_k) = J$ $\forall$ Committable Lines

IV. Results and Analysis

In [2], we examined overall system cost with changes in topology. In this paper, we analyze other economic indicators, including payments to generators and payments from loads, based on a nodal marginal price settlement. We also examine various ways of identifying transmission value.

The nodal price, or locational marginal price (LMP), is the marginal value of energy at a given location in the network, and is calculated as the dual variable of the power balance constraint (3). System cost is the sum of all the costs in the system to meet the load. In the present model, this comprises variable generator cost. Generator revenue is the amount generators are paid based on nodal pricing, LMP times amount produced, common in several restructured markets in the US. Generator rent, then, is the difference between cost and revenue for an individual generator. Load payments are the nodal payments, LMP times amount consumed.

In this paper, we are defining congestion rent as the difference in LMPs across a line times the flow of power across the line (6). This form of pricing has been shown to capture the value of both the capacity of a line and the electrical properties, and has been called admittance pricing in the literature [3], [4], and [5]. The flowgate price is the shadow price of the capacity of a line, or the value of increasing the thermal capacity of a line.

The sum of all FMPs times its respective line flow is equal to the total system congestion rent (6).When a line is not congested, the FMP is zero; therefore, the value of the admittance, or other electrical characteristics of the line, is equal to the LMP difference. A congested line is one that has a non-zero congestion rent, because even though there may be unused capacity (or an FMP of zero), the other electrical properties of the line ensure that no additional power can flow over it under the current system dispatch.[2] In other words, these lines are congested with respect to admittance. For more information on flowgate and admittance pricing, see [3], [4], and [5].

$$\text{Congestion Rent} = (LMP_n - LMP_k) P_{nk} \tag{6}$$

$$\sum_n FMP_{nk} P_{nk} = \sum_n (LMP_n - LMP_k) P_{nk} \tag{7}$$

A. System Cost, Revenues, Rents, and Load Payment

The IEEE 118-bus test case was used to test and analyze the transmission dispatch formulation. The transmission unit commitment problem was written in AMPL, and solved with CPLEX version 10.1. Data for the IEEE 118-bus test system was downloaded from the University of Washington Power System Test Case Archive [6]; transmission line characteristics and generator variable costs were taken from the network as reported in [7].

The system consists of 118 buses, 186 transmission lines, 19 committed generators with a total capacity of 5,859 MW, and 99 load buses with a total load of 4,519 MW. Table I provides an overview of the components that are modeled within the IEEE 118 test case. All generators have a minimum operating capacity of zero MW.

Table I. IEEE 118 Network Data

		Capacity (MW)			Cost ($/MWh)	
	No.	Total	Min	Max	Min	Max
Transmission	186	49,720	220	1,100		
Generators	19	5,859	100	805	0.1897	10
Load	99	4,519	2	440		

As stated above, the objective function is to minimize generation cost. The optimization problem was solved multiple times allowing for different number of lines to be taken out. In particular, optimal solutions were found for J={0,…,10}, where J is the number of lines allowed to be open, enforced by (5). There is no guarantee that the generation cost will not increase as J increases since (5) is an equality constraint. Setting (5) to be an inequality (less than or equal to) constraint would ensure that the generation cost does not increase; however, an equality constraint reduces computation time and happened to produce the same results.

In the J=0 case, in which no transmission lines are opened, the system cost of meeting this load is $2,054/h. Two of the 186 lines are fully loaded, or congested. The problem was run for J unrestricted as well, but this did not solve to optimality. The best found solution to the unrestricted J problem, which we reference in figures as “best”, has a cost of $1542/hr with 38 lines removed [2].

Figure 1 displays the fluctuations in generation cost, generation revenue, generation rents, congestion rents, and load payment for various solutions to the transmission unit commitment problem for varying values of J (J={0,…10}) as well as two sensitivity cases discussed in later sections and the

[2] Losses are not modeled so a LMP gap exists only when the line is congested under the definition defined above.

best found solution. Case 1 and case 2 are discussed in sections VI.C and VI.E respectively; the data presented throughout section IV for case 1 and case 2 represent the best found solution for these sensitivities (the 120 minute solution and the iteration 3 solution). The sensitivity cases are presented here to increase the data for comparisons. The values in the figure are displayed as percentages of results from the J=0 case, i.e. the percent values reflect the specific case's value divided by the J=0 case value. For example, generation rent is $1795/hr for J=0 and 122% of that, or $2192/hr, for J=3. Because these are percentages, the values shown do not add up in the way the actual values do; thus, the percentage value for generation rent plus cost does not add up to the percentage value for the generator revenue.

The case where J=0 has a generation cost of $2054/hr, generation revenue of $3850/hr, generation rent of $1795/hr, congestion rent of $3907/hr, and load payment of $7757/hr. Note that the congestion rent is unusually high; typically congestion rent is 5 to 10 percent of load payment. The best found solution reduces operating cost to $1542/hr, which is 75.1% of the J=0 cost of $2054/hr.

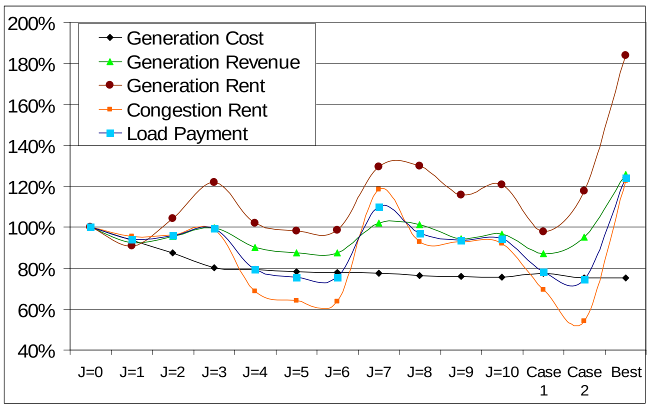

Figure 1. Cost, Revenue, Rents, and Load Payment Propagations with J

Results from Figure 1 indicate that for the majority of cases both the generators and the consumers are benefiting in comparison to the case with no lines removed; the generator rents are typically higher while the load payments are almost always lower than in the J=0 case. The load payment only increases in the J=7 case and in the best found solution. Congestion rents, in contrast, are generally lower than those calculated in the J=0 case. One key result is that generation revenues, congestion rents, load payment, and generation rents fluctuate fairly dramatically as J changes. Figure 2 displays the differences, from all cases as described above, in generator costs, generation rents, and congestion rent; the load payment equals the sum of those three terms.

As was noted in [2], although the best found solution occurs when 38 lines are opened, the majority of savings in generation cost can be realized when restricting J to a very small value, J=3. This suggests that a solution with significant savings can be obtained in a short amount of computational time. However, the preferred stopping criteria would be to allow the transmission dispatch program to run for the entire amount of time available. This is a potentially controversial choice precisely because of the fluctuations in payments. Take, for example, the significant differences in wealth transfers between cases J=6 and J=7 as shown by Figure 2. Even though there are only minor differences in the generation cost between solutions, the other results, i.e. load payment, generation revenue, and congestion rent, are very different. Unhedged loads would prefer J=6 to J=7, because they save nearly $2500/hr, yet those receiving transmission congestion rent would prefer J=7 to J=6, since their payments would be higher.

Likewise, there are significant differences in wealth transfers between case 2 and the best found solution. Case 2 has a much lower load payment than the best found solution while the best found solution has only a $4/hr lower generation cost. Case 2 also has only 15 uncommitted lines as compared to the 38 uncommitted lines for the best found solution.

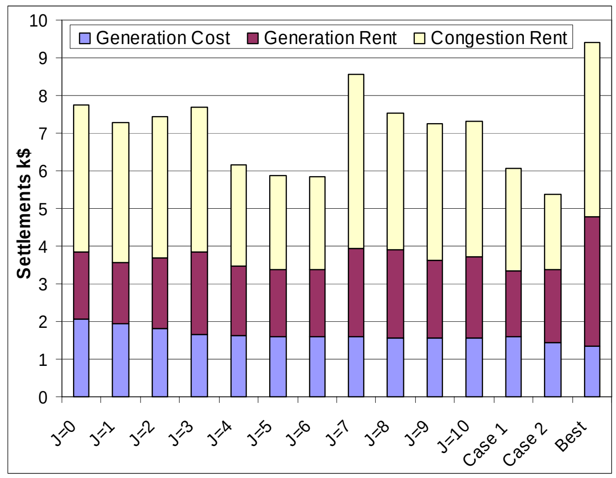

Figure 2. Load Payments and Wealth Transfers

B. LMP Results and Analysis

Figure 3 shows the average and extreme percent changes for the LMPs for J=1 through J=10 as compared to J=0. For instance, the maximum change in LMP for case J = 6 is 79%, corresponding to bus 77 changing from 0.16 $/MWh for J = 0 to 0.29 $/MWh for J = 6. The best found solution and the J=7 case have the largest percent increases in LMP, which occurred at bus 77 for both cases and the large increase was due to the opening of a nearby line. For J=7, the LMP changed from $0.16/MWh to $3.69/MWh, a 2159% change in LMP that is not shown in the figure. The best found solution had a 2271% change in LMP that is also not shown in Figure 2. Bus 77 has a load of 61 MW.

Figure 4 depicts the changes in the minimum and maximum LMP over various values of J, as well as the change in LMP at the buses with the largest and smallest LMP values in J=0. This serves to illustrate overall variation in the system LMP range and indicate the potential for fluctuation in individual bus LMP. Bus numbers are appended with "L" or "G" to identify a load bus or a dispatched generator bus, respectively, a classification followed in the rest of the paper. Overall, LMPs range from as high as $10.06/MWh in the best found solution to -$0.35/MWh in J=5. Since generator costs range from about $0.20/MWh to $10/MWh, the large variation in

LMP is not unexpected. However, individual buses can experience large changes in LMP depending on the value of J. Bus 89, for example, ranges from \$10.06/MWh in the best found solution to \$4.79/MWh in J=6. The most expensive bus in the J=0 case has its LMP drop down to 60% of its initial value in case J=6.

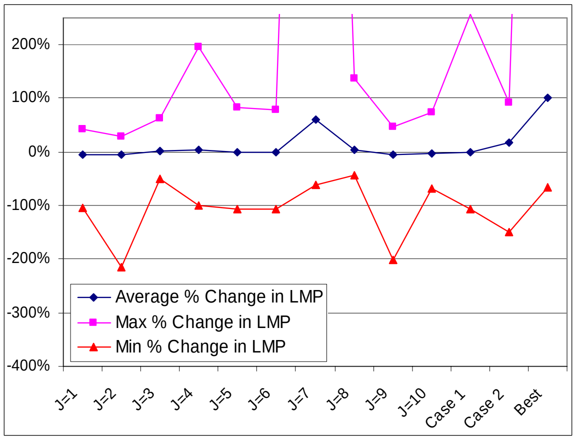

Figure 3. Average, Max, and Min Percent Change in LMP

There also are negative LMP values in some of the cases. This suggests that the altered topology may be creating a bottleneck around a cheap generator or a situation where additional load would create beneficial flows. Bus 77, which had the lowest LMP in the J=0 case, has a negative LMP, -\$0.19/MWh, for J=2 but then increases to \$3.69/MWh for case J=7. These large variations in LMP are further examples of the impacts of changing the topology of a network, and the potential uncertainties for consumers and producers.

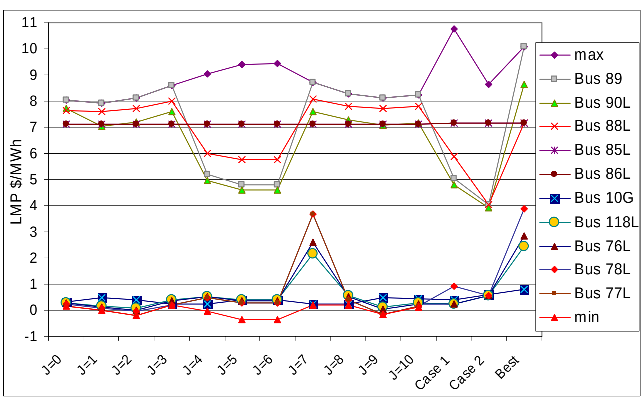

Figure 4. Largest and Smallest LMPs

One interesting result is that the LMPs for the expensive buses are lower for J=4, 5, and 6 as compared to the J=0 case but the LMPs are higher after J=7, except for bus 90. The cheap buses have a higher LMP for J=4 through J=8 but then have a lower LMP than the J=0 case for J=9 and J=10, except for bus 10. In other words, as more lines are taken out at least some of the expensive buses experience an increase in LMP while some of the cheaper buses see a decrease in LMP.

Figure 5 shows the largest variance in LMP for a load bus and a dispatched generator bus. The MW size of the load and generator are listed. The generator has a price of 0.95 \$/MWh in the base case but has a price that is more than 250% higher for J=7. This generator is the second largest generator and is fully dispatched, making the variation in LMP even more significant. The LMP at the load bus fluctuates from over \$6/MWh to -\$0.37/MWh. A LMP of \$6/MWh is high for this network, so this load may go from being charged one of the higher LMPs to being paid to consume.

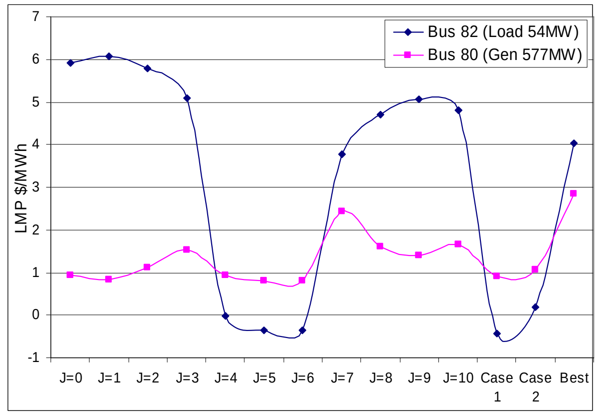

Figure 5. Largest LMP Variance for Dispatched Generation and Load Bus

Figure 6 shows the LMPs for the buses that have some of the highest variances in LMP over values of J. Bus 83 experiences a \$3.16/MWh increase in LMP for J=6 but has a \$1.84/MWh decrease in LMP for J=7; these two solutions differ by \$5/MWh. Thus, bus 83, which is a load bus, faces a difference of \$5/MWh, and a difference in total payment of \$100/h, between these two solutions.

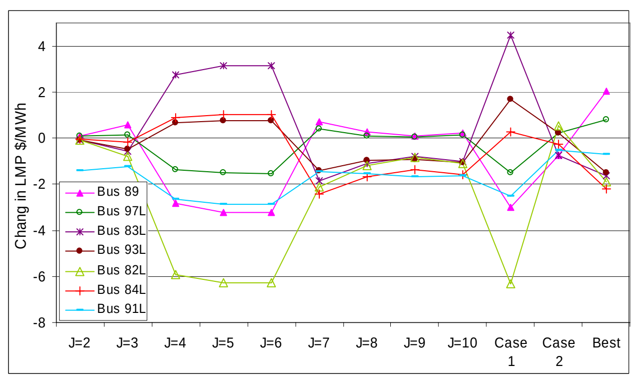

Figure 6. Change in LMP Values

C. Congestion Rent Results and Analysis

Figure 7 portrays the extreme percent changes in congestion rent for a single line between J=0 and J={1… 10}. The figure displays the maximum and minimum percent change in congestion rents for a single line as compared with its value in the case with no open lines allowed. Some of these percent changes are dramatically high; this stems from near-zero congestion rent values in the J=0 case. There are some cases in which a line had no congestion in the J=0 case but is congested once the topology of the network is altered. These lines are ignored in this figure because such a change produces an infinite percent change in congestion rents. For J=8, the percent change values are over 20,000% so they are not displayed in Figure 7. Table II lists the number of capacity-congested, i.e. fully loaded, lines and the number of lines with non-zero congestion rent.

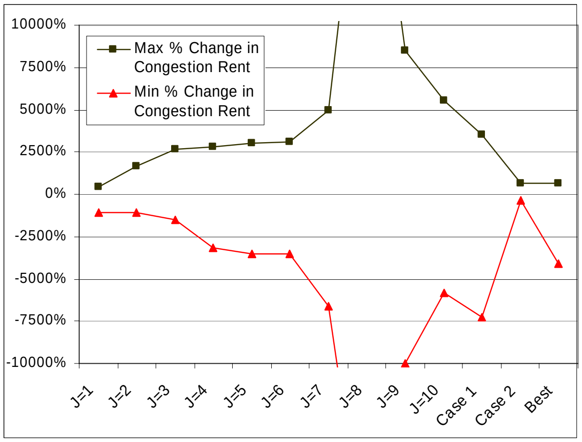

Figure 7. Max and Min Percent Change in Congestion Rent

Table II. Number of Thermally Congested Lines and Lines with Congestion Rent

	J=0	J=1	J=2	J=3	J=4
Lines with Congestion Rent	161	155	159	155	154
Fully-loaded Lines	2	2	2	3	3
	J=5	**J=6**	**J=7**	**J=8**	**J=9**
Lines with Congestion Rent	152	149	151	147	137
Fully-loaded Lines	2	2	4	3	3
	J=10	**Case 1**	**Case 2**	**Best**	
Lines with Congestion Rent	133	108	102	97	
Fully-loaded Lines	4	2	4	4	

Figure 8 shows congestion rent for lines with large variation over the case solutions. Negative congestion rent values reflect a line flow that is flowing from an expensive bus to a cheaper bus. Congestion rent on the line between bus 77 and 82 goes from positive to negative. The line flow direction is the same for J=0 and J=6, in the direction of bus 77 to 82; however, the high LMP is at bus 82 for J=0 and at bus 77 for J=6. Thus, the flow is from the cheap bus to the expensive bus in J=0, and from expensive to cheap in case J=6. The line connecting bus 92 and 89 has its congestion rents ranging from 23% to 133% of the base case throughout the solutions. This further demonstrates the uncertainty an unhedged market participant may face once the topology is changed, thereby increasing the incentive to hedge.

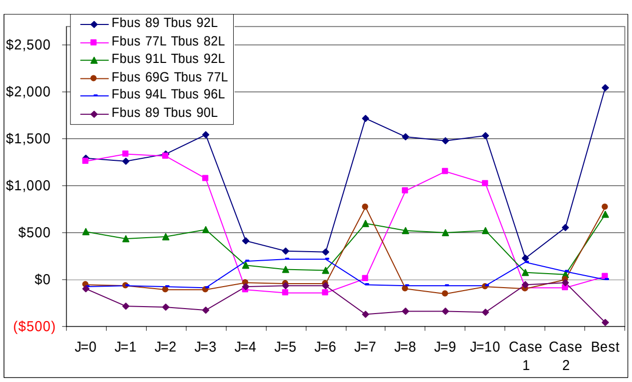

Figure 8. Congestion Rent Fluctuations

Figure 9 displays significant changes in congestion rents. The line between buses 84 and 85 experiences a $2087 increase in revenue for J=6, over J=0, but only an increase of $76 in J=7. Note that the change in congestion rent is affected by both a change in line flow as well as LMP difference. The line between bus 86 and bus 87 experiences a decrease in congestion rent for J=6 but an increase in congestion rent for J=7.

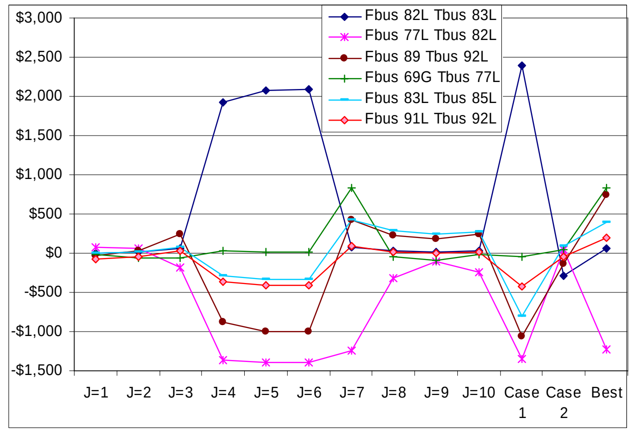

Figure 9. Changes in Congestion Rent

D. Flowgate Results and Analysis

Unlike congestion rent, which can accrue to a line whether it is thermally constrained or not, a flowgate marginal price (FMP), or shadow price, is non-zero only when the capacity limit is binding. Despite the large changes in LMPs and congestion rents, only seven unique lines are congested in all cases J={0…10}. Figure 10 displays the largest flowgate marginal prices (FMP).

In cases J=0 through J=3 the line connecting bus 77 to bus 82 has a relatively high FMP, then the line is uncongested for J=4 through J=6, and is congested again for J=7 and higher. Another interesting result is the change in FMP for the line connecting buses 92 and 89. The FMP stays relatively high at first but drops significantly for J=4 through J=6 and then becomes one of the larger FMPs again from J=7 on. These examples demonstrate the uncertainty present in FMPs when the topology is changed as well as the variation in results from one minor change in topology to the next.

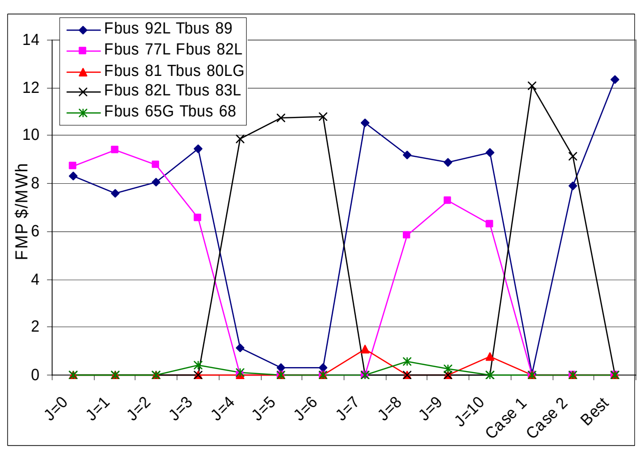

Figure 10. Largest FMPs

V. Computational Statistics

Generally, large production systems cannot be solved to optimality or optimality cannot be proven even if it is found. In theory, this problem is NP hard and no special structures or techniques have yet been developed to solve it quickly to optimality. The IEEE 118 bus test case could have 2^{186} (or approximately 10^{56}) alternate topologies. Even if each problem could be solved within one pico second, it would take 10^{27} billion years to solve the IEEE 118 bus system to optimality by complete enumeration. Nevertheless, solutions that improve on the static case can be found in reasonable time. The practical implementation of this method would be to allow the solver to take the full time available for a solution. Since finding and especially proving optimality is unlikely, this creates the need to analyze the intermediate, suboptimal results that improve on the static topology.

Table III lists the number and type of variables and constraints within this problem. The J=0 case is a linear program (LP) while the rest of the test cases, J=1 through J=10, have the same number of variables and constraints and are mixed integer programs (MIP). Redundant variables and constraints are eliminated during the presolve phase of the problem, conducted automatically by AMPL. The residual variables and constraints are identified in Table III by "post presolve." The computer specifications are listed in Table IV.

Table III. LP and MIP Variables and Constraints

IEEE 118	LP	MIP
Total Variables:	323	509
Binary Variables:	0	186
Total Linear Constraints:	627	1000
Upper or Lower Bound Constraints:	323	509
Total Variables (Post Presolve):	315	492
Binary Variables (Post Presolve):	0	177
Linear Constraints (Post Presolve):	482	833

Table IV. CPU Specifications

	Type 1	Type 2	Type 3
No. Processors	2	2	4
CPU speed	3.4 GHz	2.8 GHz	2.8 GHz
Memory total	1.0 GB	2.1 GB	2.1 GB
Swap total	2.1 GB	3.1 GB	3.1 GB

Figure 11 displays the computational statistics, which include solution time, the total number of simplex iterations, and the number of branch and bound nodes for solving J=0 through J=10 to optimality.[3] The computational statistics for the best found solution are listed in [2]. J=0 is a LP so the number of branch and bound nodes is zero; this value is not shown on Figure 11 as it is in a log scale. CPLEX has a default relative MIP gap of 0.01%, which means without changing anything the solver stops once the gap between the best integer solution and the objective of the best remaining node divided by the objective of the best remaining node is 0.01%. J=0 through J=10 were solved based on reaching this relative MIP gap as well as solved to optimality. The solutions were the same and the computational statistics were only slightly different.

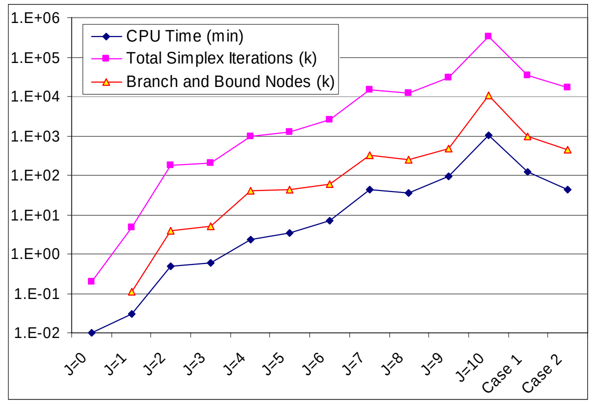

Figure 11. Computational Statistics on Computation Time, Simplex Iterations, and Branch and Bound Nodes

VI. Sensitivity Results

Various sensitivities were tested on this model. In the first sensitivity, the model formulation itself is examined; we test the formulation of the bus angle constraints to see if it has an effect on the results. We then look at the sensitivity of the model results to the particular data being used by running the OPF with different generator costs. Last, we examine possible computational strategies for improving the trade-off between run time and the objective function. The solutions within the sensitivity studies are stopped once they reach a relative MIP gap of 0.01%.

A. Bus Angle Difference Constraint

The initial model implements a constraint that limits the magnitude of the bus angle to be less than 0.6 radians. In this sensitivity, the constraint is changed to limit the difference of bus angles between connected buses to be within the range of ±0.6 radians. The J=0 case serves as the base case for this sensitivity, with a generation cost of \$2053/hr, generation revenue of \$3684/hr, generation rent of \$1630/hr, congestion rent of \$3855/hr, and load payment of \$7539/hr. Figure 12 shows the values for J={1…10} as a percentage of the values obtained from J=0 for this sensitivity.

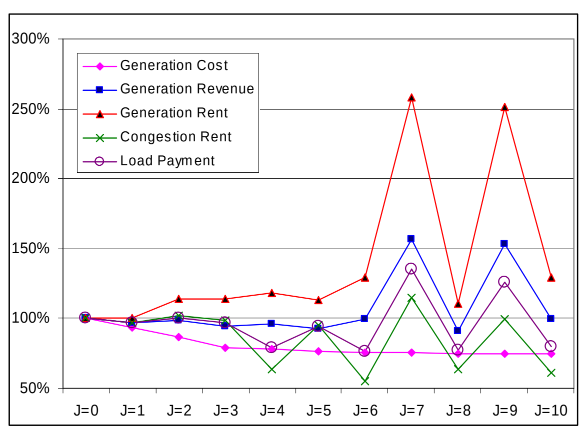

Figure 12. Value Propagations with J for Sensitivity Study A

[3] Note that these results are run on various shared computers that face different loading levels at different times so the CPU time may not be the best indicator of the difficulty of the problem; total simplex iterations and branch and bound nodes are also indicators of the difficulty of the problem.

By placing the constraints on bus angle differences instead of on the overall bus angle, the feasible region of the problem is increased, thereby making possible a lower objective. At first, there is no significant difference between the original model's results discussed in section IV and this model's results; however, there are significant differences for the middle solutions, J=5 through J=7. Just as before, there is no clear trajectory for the various values. J=7 demonstrates a large jump in load payment while J=8 has a small value and J=9 has a significant increase like J=7. Again, the different topologies will benefit certain unhedged market participants and hurt others and, at the same time, one cannot predict who will benefit and who will not. Last, it is important to note that none of the bus angle difference constraints were active for any of the solutions. This may not be the case if more lines were to be taken out but it holds for these solutions.

B. Expensive Generators

Next, we examine the affect of the five most expensive generators. The majority of generators had costs that were less than \$1/MWh but there were five that had costs from \$2 to \$10/MWh. The costs of these five expensive generators were halved to examine whether the large generator prices are the main driving force for the large generation cost savings as was seen in the base case. The J=0 solution for this sensitivity provided a total generation cost of \$1669/hr, generation revenue of \$3469/hr, generation rent of \$1800/hr, congestion rent of \$1690/hr, and load payment of \$5159/hr. By comparing Figure 13 and Figure 1, it is clear that the percent saving in generation cost for this sensitivity is not significantly smaller than the saving in the original study. This suggests that the existence of the expensive generators is not in fact the driving force behind the large 25 percent savings. However, additional research would be needed to determine whether dramatic savings are a feature of dispatchable transmission in general.

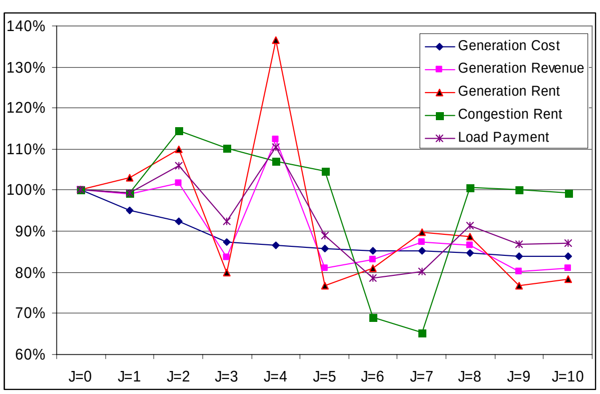

Figure 13. Value Propagations with J for Sensitivity Study B

C. Stopping Times

This sensitivity study examines the practical implementation of this model. In production systems, the system operator would look for a solution within a certain time frame. (Reliability standards may pose a restriction on whether a particular line may or may not be switched out, but the operator would not choose the J value, e.g. to have seven uncommitted lines instead of eight.) Thus, the model was simulated for different stopping times to analyze how the results may differ.[4] From the original model, J=3 provides an objective that is less than \$1650 within one minute. A bound of \$1650 is placed on the objective so that undesirable solutions can be ignored. This cuts the computation time as it eliminates the exploration of inferior branches. The results are displayed in Figure 14. The original results for the model presented in section IV are listed in Figure 14 as Base Case J=0. The number of lines chosen to be uncommitted in the current solution that were also uncommitted in the previous solution is displayed in Table V along with the total number of uncommitted lines in parentheses.

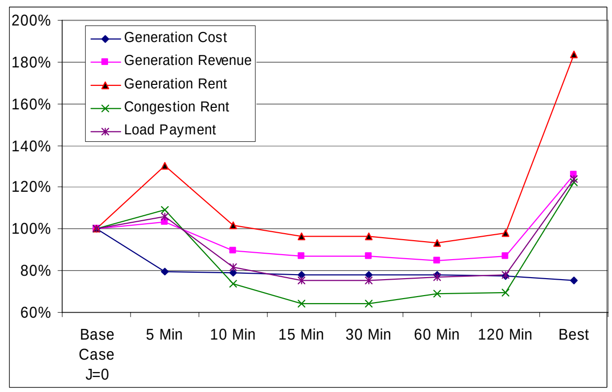

Figure 14. Value Propagations for Various Stopping Times Compared to Original Base Case J=0 for Sensitivity Study C

Table V. Number of Uncommitted Lines in Previous and Current Solution (Total Uncommitted Lines)

5 min	10 min	15 min	30 min	60 min	120 min
0 (36)	12 (34)	24 (36)	36 (36)	17 (35)	13 (35)

The solution decreases substantially in the first five minutes and then plateaus. The solution for 15 minutes and 30 minutes are exactly the same. Thus, it appears that while a good solution is found quickly, more solution time does not result in improvements to the solution.

Allowing the program to run for 2 hours provides an inferior solution to the result from J=9, which has about the same solution time but a lower generation cost. The goal is to find a good solution as fast as possible, but additionally we may want to minimize the number of open lines for reliability reasons. In other words, if two solutions have near-identical objective functions the one with fewer open lines is likely to be preferred. These factors suggest that letting the algorithm run for a specific amount of time while not limiting the number of open lines may not be the best approach. The best approach may need to be tailored to specific networks, a possible area of future research into the best practical approach for this problem. Section VI.E. provides a simple heuristics approach that does not guarantee optimality but shows that a close to optimal solution can be obtained within a short time.

[4] To reduce computational burden, no more than 40 lines were allowed to be open.

D. Iteratively Remove and Fix Lines

In [2], it was shown that the set of uncommitted lines for smaller J values are not subsets of the solutions for cases where J is larger. Therefore, an approach to iteratively solve for the next best line to open is not guaranteed to achieve optimality. This can be seen in Table VI, which shows changes in line status for the results from section IV, J = {1…10}. Line out (or in) reflects an uncommitted (committed) line in the present solution that was a committed (uncommitted) line in the previous solution.

Table VI. Change in Line Status from Previous Case: Line Out (Line In)

	J=1	J=2	J=3	J=4	J=5
Lines	153	132	136	162	64
	J=6	**J=7**	**J=8**	**J=9**	**J=10**
Lines	70	86, 146 161 (70, 162)	35, 38, (86)	72	34, 67, 68, (35, 72)

E. Iteratively Remove and Fix 5 Lines

As previously stated, optimality cannot be guaranteed by taking a previous solution and building on from it by allowing more lines to be uncommitted. For practical implementation, the goal is to obtain a good solution within the time available and with minimum open lines. This section presents the results of using an iterative approach by taking the previous solution as fixed and solving for the optimal topology based on allowing a certain number of additional uncommitted lines. The chosen number of lines to be removed during each iteration would depend on the tradeoff between solution time and the generation cost savings. For this test case, we solve for the optimal topology when 5 lines are allowed to be uncommitted, fix the solution's chosen 5 lines as open, and then repeat the process by allowing an additional 5 lines to be uncommitted.

Figure 15 presents the results as percentages of the original J=0 case presented in section IV, identified as Base Case J=0 in the figure. After three iterations, this method produced a generation cost of $1549/hr, generation revenue of $3662/hr, generation rent of $2113/hr, congestion rent of $5773/hr, and load payment of $5773/hr.

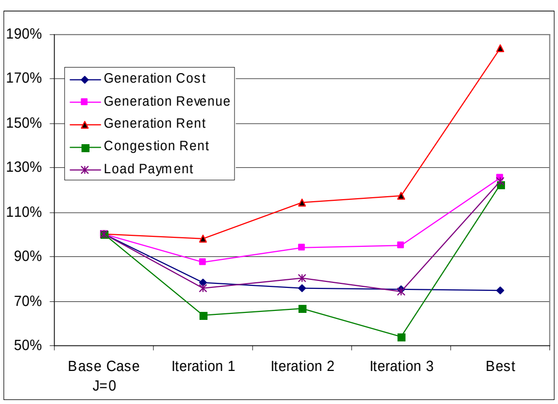

Figure 15. Value Propagations for Base Case and Iteration Approach Sensitivity Study

The first iteration is the same as the original solution for J=5 in section IV. The second iteration takes the chosen uncommitted lines from iteration one, fixes them, and allows five additional lines to be uncommitted, making the total uncommitted lines to be ten. This process is repeated for every iteration. After only three iterations, this method has achieved 24.6% savings and it is within $4 of the best found solution. This was accomplished within 42 minutes, as opposed to taking more than 2 hours to achieve similar results based on the original method. The fourth iteration was infeasible after 20 hours with over 10 million branch and bound nodes. Further investigation showed that allowing just one additional line to be uncommitted after iteration three provided less than 10^{-5}% benefit. This suggests that the solution from this method cannot be improved after three iterations, or that the additional benefit is not worth the solution time. This is not a generic result for this approach but a unique result for using this approach on this specific network.

This is a simple heuristics approach that demonstrates the practical possibilities of better heuristics obtaining very good solutions within a moderate amount of time. The data in Table VII shows that the chosen lines are not necessarily the same as the uncommitted lines of the current best found solution reported in [2], but that the approach still provides significant savings. To get such results in a short period of time took some experimenting by the authors. The authors do not claim that this is the best heuristic or that such an approach would work for practical problems. The purpose of this sensitivity is to demonstrate the value of good heuristic methods as well as the need to investigate such valuable approaches.

Table VII. New Uncommitted Lines from Previous Iteration

Iteration #	1 (J=5)	2	3
Lines	64, 132, 136, 153, 162	35, 38, 86, 148, 161	70, 73, 85, 91, 126

VII. Policy Implications

The results throughout this paper demonstrate the uncertainty and potential variability in the total and individual values of generation costs, revenues, and rents, congestion rents, and load payments, even when the total generation costs differ only slightly.[5] The values of LMPs are sensitive to the particular topology selected, and the selected topology depends on the stopping criteria and solution heuristics.

Since individual bus LMPs may change dramatically between solutions, the chosen network dispatch may cause significant fluctuations for unhedged market participants. Determining the optimal topology for a practical network is likely to be extremely time consuming, if not impossible, thus a certain amount of discretion will exist in choosing the solution, e.g. when to stop, how many lines to open, etc. The opportunity exists to change the topology of the grid strategically to make one participant better off while making others worse off. These topology decisions, therefore, should be made by an independent party with no financial interest in the settlement.

Even still, determining a stopping criterion may be a very sensitive topic. An operator may have a choice between solutions with system costs that differ by a trivial amount but have significant wealth transfers, as was evident in Figure 2

[5] These results are consistent with those found in [8].

with case 2 as compared to the best found solution. This hypothetical situation raises the question as to whether an operator should care only about minimizing generation cost. Perhaps there should be additional objectives, such as minimizing the number of open lines or the load payment. Identification of additional objectives is a job for policy-makers, and would depend on societal values or objectives for the market.

Another implication of these potentially volatile and unpredictable prices is the need for a forward market in which to hedge the real-time prices. Real-time prices are useful as marginal indicators, sending financial signals to users and suppliers to alter behavior based on real-time conditions. However, it is likely that most risk-averse market participants will want to hedge the risk of volatile real-time prices by trading in longer-term forward markets in which the negotiated or clearing price will be less uncertain. Forward contracts can also help to suppress the ability and incentive to exercise market power [9].

Point-to-point financial transmission rights are common in many restructured markets, and allow market participants to hedge forward contracts or speculate on price differences. Typically in markets that employ FTRs, the system operator auctions the rights before the real-time dispatch of the network is determined. Due to changes in load profiles or contingencies, sometimes the amount of congestion rent collected does not equal the amount of FTR payments, resulting in under-funded transmission rights [10]. To achieve revenue adequacy for transmission rights, the system operator may need to implement a rationing/wealth transfer rule, such as pro-rating FTR payments, which can be controversial because it can impact the financial positions of generators, consumers, and FTR holders.

The implementation of transmission dispatch should not impact the normal FTR mechanism, since the presence or absence of a line does not eliminate the existence of point-to-point differences in prices. Market participants that hold FTRs for the purpose of hedging may face risk due to the policy on revenue inadequacy of transmission rights, but perhaps not more-so than they face today. Speculators holding FTRs, on the other hand, may be exposed to additional risk due to added uncertainty in volatility of LMPs as well as the risk associated with revenue inadequacy policy. It would be interesting to explore to what degree transmission dispatch changes the characteristics of revenue adequacy and transmission rights.

Volatile LMPs may not be altogether negative. Not only do they create an incentive for market participants to hedge and sign long-term contracts, they may also make strategic behavior more difficult. In a sense, transmission dispatch allows transmission lines to compete in the market dominated by generators. The introduction of additional competitors can reduce the influence of existing competitors, thus limiting their ability to control prices.

Ultimately, optimizing the transmission network can result in a more economically efficient system, otherwise the network will not be altered. A more efficient system dispatch produces more surplus, and with more surplus, it is possible for the ISO to implement wealth transfers that result in Pareto improvements for all market participants. While questions of surplus allocation are not a concern for completely vertically integrated utilities, since in a sense all surplus accrues to the utility, transmission dispatch would still be beneficial.

VIII. Future Work

Future work should consider the impact on reliability when changing the topology of the network. An open line may help or hurt reliability. A security constrained optimal power flow may be needed to determine which lines can be opened. The results show that there can be significant savings by having only a few uncommitted lines and since solution time would be an issue for large networks, it may also be possible to focus only on key lines that do not affect reliability. Multiple solutions can provide similar objectives even though the number of open lines can be dramatically different. Research is needed to determine whether it is appropriate to not only minimize generation cost but also minimize the number of open lines or some other objective that would consider the impact on reliability among these similar solutions. Stability studies should also be investigated to determine the impact of having a significant number of uncommitted lines and having to recommit them during a disturbance. Future work should also include the development of an ACOPF transmission unit commitment model.

IX. Conclusion

This paper has demonstrated the uncertainty to which market participants may be subject when the topology of the network is modified by choosing certain lines to be open in order to achieve a better dispatch. Analysis of the IEEE 118-bus test case results in higher generator payments and lower load payments, in general, when the transmission network is optimized.

An important finding of this paper, and one that is consistent with [8], is that nodal prices can vary dramatically between topologies, even topologies that have similar system costs. Thus, the economic impact on market participants relies heavily on topology and can be unpredictable in the real-time or short-term market. This implies that (1) an unbiased and independent actor with no financial interest in market settlement should be in charge of determining topology to avoid intentional manipulation, and (2) hedging will be important for market participants. We also find that computational heuristics may play an important role in solving the transmission commitment problem.

Since the problem is, in theory, NP hard, optimality would most likely not be achieved in a production setting; however, significant savings can still be achieved in reasonable amounts of time as has been shown by the results presented in this paper. If an optimal solution is not found, allowing the solver to use all the time available appears to be the best strategy. These suboptimal solutions, while improving system cost, can have drastically different implications for varying market participants; this may make determining the appropriate stopping criteria a controversial policy decision.

There are many potential policy implications of transmission dispatch. Market participants would need to be informed of the potential for volatile real-time prices so they can prepare by signing forward contracts or other long-term agreement. Criteria for choosing an optimal topology would need to be clear and unbiased. A revenue-adequacy policy for transmission rights would need to be implemented. However, some potential benefits, in addition to increased market surplus, may include reduced exercise of market power, due to an increase in long-term contracts and uncertainty in real-time prices.

Overall, we have discussed benefits of transmission unit commitment, the potential financial impact on market participants, the new decisions and questions that a system operator may face given a change in topology, and whether such an approach can be applied in a practical setting. This paper has also identified future areas that need to be studied to determine the complete effect a transmission unit commitment program would have on the network.

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