Transmission Congestion Analysis in the Eastern Interconnection using POMS

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Abstract—**A methodology based on the security-constrained unit commitment (SCUC) is applied to analyze the transmission congestion in the Eastern Interconnection of the United States for 2008 and 2018. The proposed SCUC tool for this study is referred to as the POwer Market Simulator (POMS). The identified congestions are visualized along with the Geographical Information System (GIS) data and compared with the results published by the U.S. Department of Energy's National Electric Transmission Congestion Study (NETCS) in 2006. The POMS study also provides the locational marginal price (LMP) information in the Eastern Interconnection, which is not available in the NETCS report. The POMS simulation results for representing congested branches and LMPs could be applied to the future transmission expansion planning studies.**

Index Terms—**Transmission Congestion, SCUC, LMP, National Electric Transmission Congestion Study, Eastern Interconnection in the United States**

I. INTRODUCTION

T HE identification of possible congestion sites is the first step in any grid expansion and reinforcement studies. The Federal Power Act (FPA) 216(a) resulted in a study of the electric transmission congestion in the United States [1]. The first congestion study report, known as the National Electric Transmission Congestion Study (NETCS) and issued in August 2006, identified congestions and constraints in the Eastern and the Western Interconnections [2]. The NETCS report included the review of the available information on historical congestion, the simulation of future congestions, and the comparison of simulation results with the historical information. Another published report analyzes the available 2007 data for assessing the transmission congestion in the Eastern Interconnection [3]. For the purpose of comparison, this paper will focus on the NETCS in 2006.

This paper focuses on the congestion studies in the Eastern Interconnection of the U.S. by applying SCUC. In addition, the congestion and LMP results are visualized along with the GIS data. The rest of this paper is organized as follows. Section II describes the proposed methodology for indentifying congestions and presents the congestion study results for the Eastern Interconnection in 2008 and 2018. The study results of 2008 are also compared with the results in the NETCS report. Section III concludes this paper.

II. METHODOLOGY FOR IDENTIFYING CONGESTION

A. Congestion Simulation

The tool used for this study is called POwer Market Simulator (POMS), which has been used extensively for power system studies for decades. The methodology in POMS simulates the hourly electricity market operation based on SCUC for identifying possible congestions[1]. The POMS simulation results have several advantages over those of the optimal power flow (OPF). A POMS simulation study considering the commitment and the redispatch of generating units will provide a more realistic picture of possible scenarios. In essence, it may be necessary to consider potential changes in the hourly unit commitment to satisfy certain constraints.

The POMS applications to the Eastern Interconnection simulation consider a decomposition and coordination strategy shown in Fig. 1. A similar procedure is followed for considering contingencies [4]-[7].
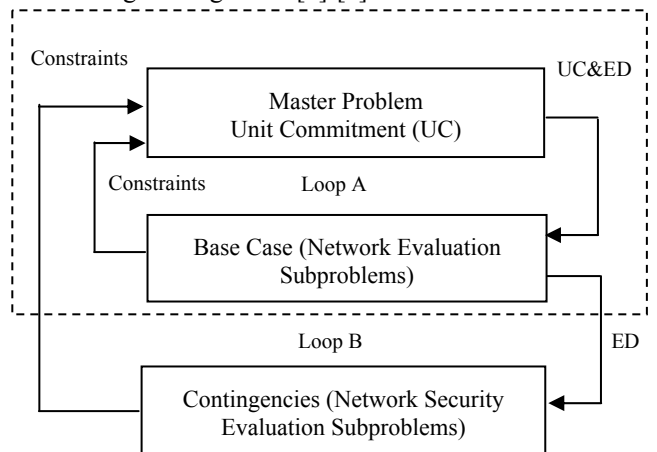

Fig. 1 SCUC Solution for the Eastern Interconnection

In this section, we utilize POMS to simulate the congestions in the Eastern Interconnection based on the 2008 and 2018 data. We compare the POMS simulation results with those in the NETCS report, referred to as NETCS results thereafter, and analyze the variations in the POMS simulation results from 2008 to 2018. Note that there are about 70,000 branches at all voltage levels in the Eastern Interconnection. We consider in the POMS simulation only those branches that are above 200kV along with 1,000 flowgates.

B. POMS Simulation Results for 2008

In this case, POMS is applied to simulate the 8,760 hours of generation dispatch and transmission flows in the Eastern Interconnection in 2008. The pertinent definitions are provided in Appendix A.

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[1] The congestion in this paper is defined as a state in which the flow on a branch has reached the branch capacity.

B1) Transmission Congestions based on the Binding Hours Metric

The POMS simulation results show that in 2008 there are 1,325 congested branches[2], 270 of which are congested in all hours. The most congested branches are in the New York and the Chicago regions. There are also several congested branches in the boundary between Georgia and Florida. Fig. 2 shows the zoomed-out version of the congested branches based on the binding hours metric.

B2) Constrained Branches based on the U90 Hours Metric

As expected, more transmission branches are constrained based on the U90 hours metric. There are 2,497 U90 branches[3], 483 of which are continuously loaded above 90% of their capacities. The U90 branches are again concentrated in the New York region, the Chicago region, and the boundary between Georgia and Florida. Fig. 3 shows the zoomed-out version of constrained branches based on the U90 hours metric.
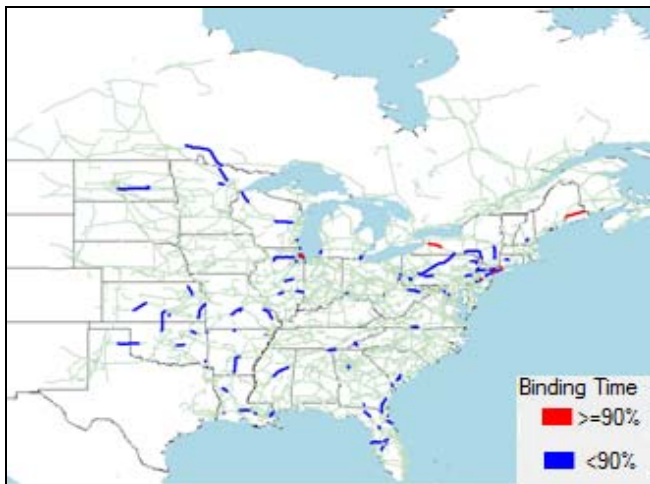

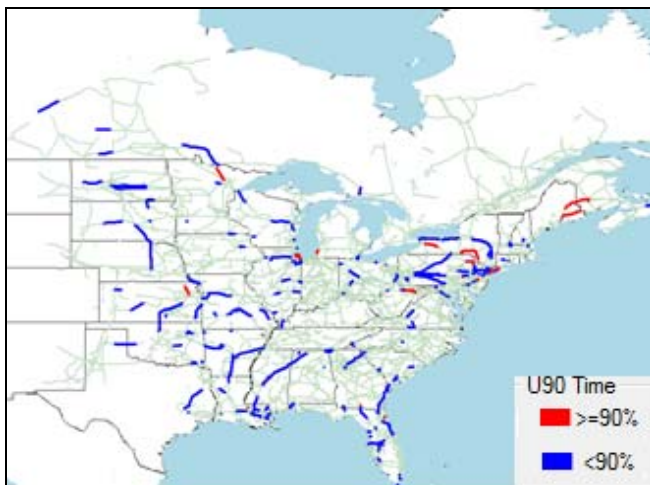Fig. 2 Binding Hours Information in 2008

Fig. 3 U90 Hours Information in 2008

B3) Number of Constrained Branches

Fig. 4 shows the number of constrained branches as a percentage of time. There are 1,325 congested branches and 439 (i.e. 33%) of these branches are congested in more than

80% of the annual hours and 600 (i.e. 45%) are congested in less than 20% of the annual hours. The U90 curve in Fig. 4 has a similar trend except that more branches are constrained based on the U90 metric. It is expected that more branches would be constrained if U75 was used as the metric.
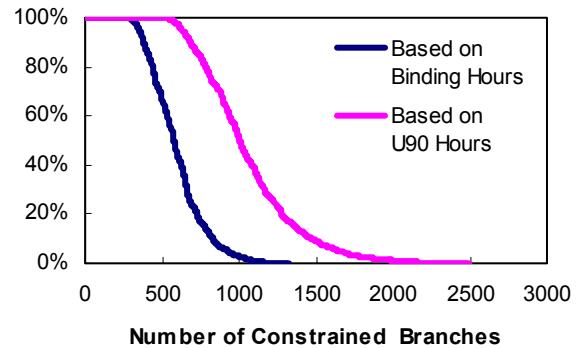

Fig. 4 Constrained Branches as a Function of Time in 2008

B4) Locational Marginal Prices

Fig. 5 shows the 2008 annual average LMPs based on the POMS simulation results. The New York region shows the highest LMPs in the Eastern Interconnection because of its limited generation capacity. Due to the existing transmission congestions, much of the low cost power from neighboring regions cannot be transmitted to the New York region. So, the LMPs in the New York region are high due to its dependence on local expensive units such as gas units and oil units for supplying the local load. The LMPs in New England and Florida are relatively high for similar reasons. Even though the Chicago region also exhibits transmission congestion, the LMPs are not as high which is partly due to the cheap coal-fired and nuclear power generation close to the load centers. Large wind developments in the Midwest could provide large sums of low cost energy to the Midwest energy markets. So, LMPs in the northwest region of the Midwest are relatively low.
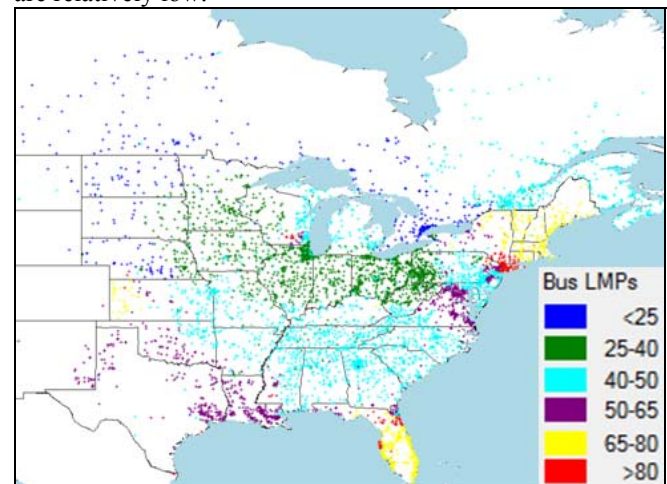

Fig. 5 Annual Average of LMPs in 2008

B5) Cost of Served Load and Congestion Cost

Based on the 2008 POMS simulation, the total cost of served load is about $172.3 billion. The total congestion cost is about $13 billion which is about 7.5% of the total cost of served load. The total production cost is about $75.3 billion. Fig. 6 shows that the production cost as a function of the

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[2] A congested branch is a branch with a non-zero binding hour.
[3] A U90 branch is branch with a non-zero U90 hour.

hourly load. A higher production cost would appear in hours 5000-5500 (July and August), which are consistent with higher loads experienced during this time.
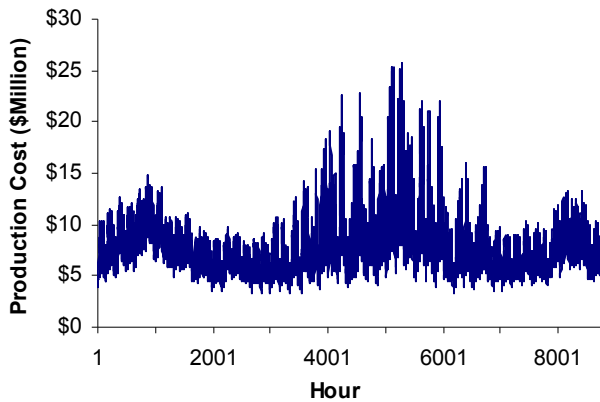

Fig. 6 Production Cost in 2008

C. POMS Simulation Results for 2018

The Eastern Interconnection is simulated in 2018 using POMS. The input data are based on the forecasts in the MISO MTEP 2008 study [8]. The loads are assumed to increase at an annual rate of 1.0128% based on the 2008 loads. The fuel prices are assumed to increase at an annual escalation rate of 4% for oil and gas, 2% for coal, and 3% for nuclear fuels. The transmission and generation projects that are under construction or are planned by 2018 in the Eastern Interconnection are incorporated in the 2018 simulation. New England and Florida, which were not included in the MISO MTEP 2008 study, are excluded from the POMS simulation.

C1) Transmission Congestion based on the Binding Hours Metric

The simulated 2018 congestion is shown in Fig. 7. There are 2,665 branches that are congested for at least one hour and 314 of those branches are always congested in 2018. Most of the congested branches are in the New York and the PJM interconnections. Certain branches in the west side of the SERC region are also congested.
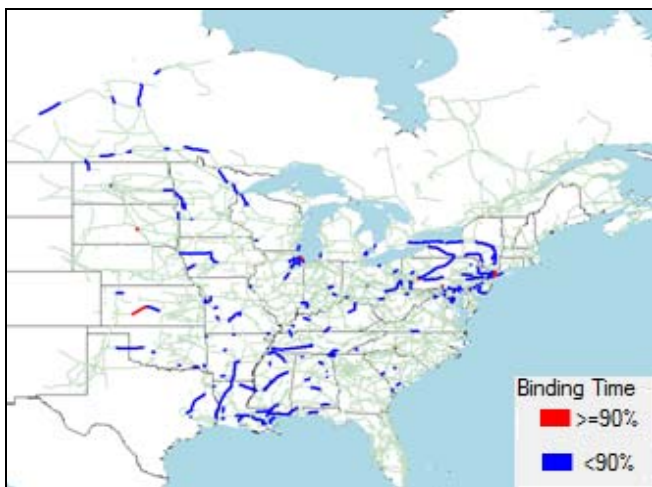

Fig. 7 Binding Hours Information in 2018

C2) Constrained Branches based on the U90 Hours Metric

Fig. 8 shows constrained branches based on the U90 metric. There are 4,239 constrained branches based on U90 and 472 of those branches are continuously loaded in excess of 90% of their capacities. Such branches are mainly located in New York and in certain parts of the PJM system (including Chicago). A few branches are also constrained in the west side of the SERC region.
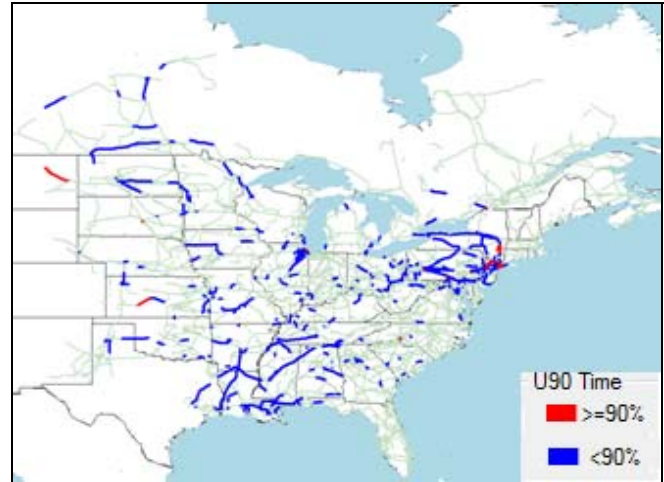

Fig. 8 U90 Hours Information in 2018

C3) Number of Constrained Branches

Fig. 9 shows the number of constrained branches as a percentage of time. Out of 2,665 branches that are congested in at least one hour, 524 (i.e. 20%) remain congested in at least 80% of the annual hours and 1,599 (i.e., 60%) are congested in less than 20% of the annual hours. Based on the U90 metric, there are 4,239 branches that are constrained, 710 (i.e., 15%) of such branches remain constrained in at least 80% of annual hours, and 2,715 (i.e., 65%) are constrained in less than 20% of the annual hours. The two curves have similar trends except that more branches are constrained based on the U90 metric.
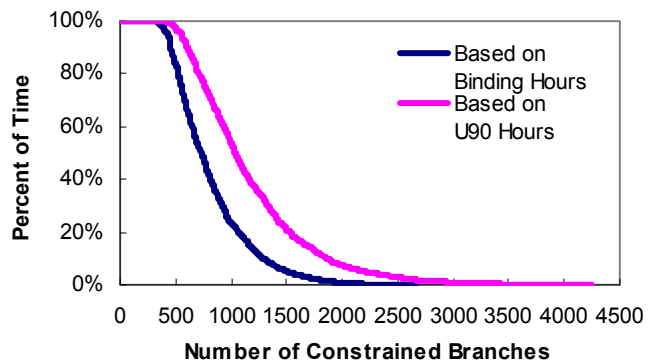
Fig. 9 Constrained Branches as a Function of Time in 2018

C4) Locational Marginal Prices

The annual average LMPs based on the 2018 simulation are shown in Fig. 10. New York has the highest LMPs in the Eastern Interconnection. The LMPs in the East Coast are generally higher than those in other regions. High LMPs are also encountered in Louisiana and Mississippi indicating transmission congestions. LMPs in Illinois and Indiana are lower than those in the East Coast because there are cheap

coal-fired and nuclear power plants close to load centers. LMPs in the Northwester region of the Midwest are significantly lower than those in other regions due to expected high penetration of wind power.
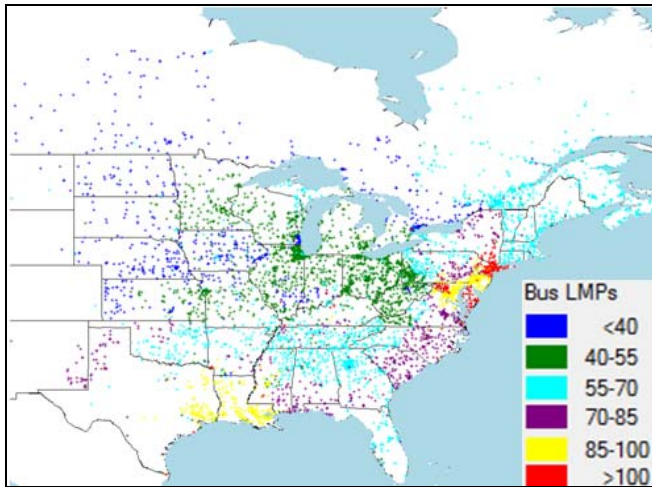

Fig 10 Annual Average LMPs in 2018

C5) Cost of Served Load and Congestion Cost

The total cost of served load in 2018 is about $230.9 billion and the total congestion cost is about 10% of the total cost of served load. The total production cost in 2018 is $83.6 billion with the hourly costs shown in Fig. 11, where higher hourly production costs appear in July and August.
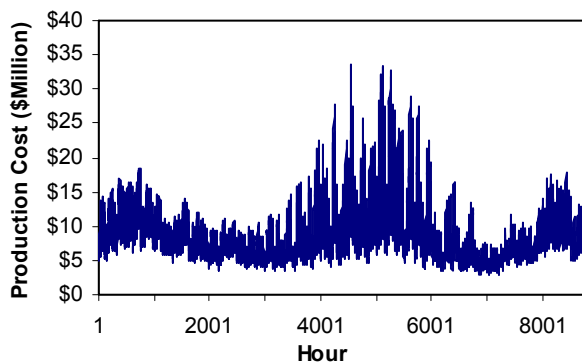

Fig. 11 Production Cost in 2018

D. Comparison of POMS and NETCS Results in 2008

In this section, we compare the 2008 POMS simulation results with the NETCS results. The NETCS report reviewed the historical congestions and analyzed the 2008 congestion in the Eastern Interconnection using the optimal power flow (OPF) model [2].

D1) Regional Congestion

The POMS and the NETCS simulation results show that congestions are concentrated in the New York and the PJM regions (including Chicago). In addition, congestions are identified at the border between Georgia and Florida. With high LMPs in Florida, the cheaper energy is imported to the state which leads to congestions at the border. These congestions were not presented in the review of historical information in the NETCS report because the actual transactions between Florida and Georgia are based on long term contracts which would limit the power flow across the Georgia-Florida border.

D2) Number of Congested Paths/Branches

In NETCS, 58 historically congested paths were identified with the detailed geographical information given in [2]. In the simulation results presented in NETCS, 171 congested transmission paths were identified in 2008. In comparison, the POMS simulation results for 2008 identified 270 congested branches that always constrained based on the binding hours metric. The difference is due to the fact that one transmission path in the NETCS report may represent several branches although the details are not given in the NETCS report.

One notable point is that both the NETCS and the POMS simulation results identify more congestions than what is reported by the historical data. This is due to the assumption in both simulations that economic transactions occur whenever is possible. A two-bus example presented in the Appendix B illustrates how economic transactions could cause additional congestions. It should be pointed out that almost all historical congestions have also been identified in the NETCS simulation results and the POMS simulation results.

D3) Constrained Transmission Capacities

Fig. 12 shows the percentage of constrained transmission capacity as a function of time and Fig. 13 shows the constrained capacity (GW) as a function time in 2008. In particular, it is shown in Fig. 12 that about 23% of the constrained transmission capacity is congested more than 80% of the annual hours based on the Binding Hours curve, and about 30% of the constrained transmission capacity is constrained more than 80% of annual hours based on the U90 Hours curve. Note that the U90 branches will always include the congested branches and that is why the U90 Hours curve is above the Binding Hours curve in Figs. 12 and 13.

In NETCS, heavy congestion occurs in only a few hours per year. For instance, 80% of the congestion occurs for less than 20% of the annual hours [2]. In comparison, the POMS simulation results in Fig. 12 show more congestion. In the latter case, 50% of the congestion occurs in less than 20% of the annual hours.
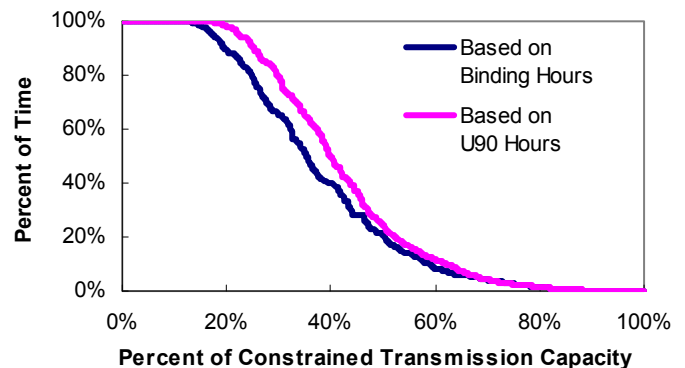

Fig. 12 Constrained Transmission Capacity (%) as a function of Time in 2008
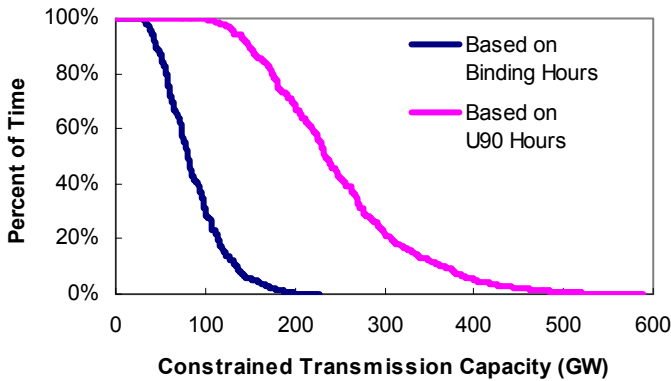
Fig. 13 Constrained Transmission Capacity (GW) as a function of Time in 2008

This difference can be attributed to the differences in the input data and the modeling details. For instance, both branch flowgate limits are taken into account in the POMS simulation, while only branch limits are monitored in the NETCS. In addition, the NETCS was completed in 2006. Thus, some transmission projects that were completed since then might not be included in the NETCS simulation. It is also possible that certain transmission projects that were assumed in the NETCS are not built and thus not included in the simulation in this paper.

In Fig. 12, the two curves coincide beyond the 60% constrained transmission capacity point, i.e., about 40% of constrained transmission capacity is constrained less than 10% of the time. The difference between the two curves is more obvious in Fig. 13. 228 GW of transmission capacity is congested based on Binding Hour metric and 588 GW is constrained based on the U90 Hour metric.

Fig. 14 also shows the constrained transmission capacity as a function of time. However, only the congested transmission branches are considered in calculating the constrained transmission capacity in both cases. In contrast to Fig. 12, the two curves in Fig. 14 are more distinguishable. For instance, 40% of the congested transmission capacity is congested as least 40% of the binding time. The same transmission capacity will be loaded to 90% or more at 70% of the time.
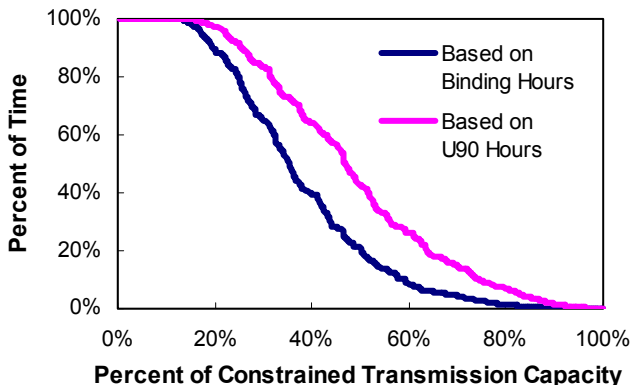

Fig. 14 Constrained Transmission Capacity as a function of Time in 2008 (congested capacity is used as base)

D4) Congestion Costs

In the POMS simulation results for 2008, the total cost of served load is $172.3 billion and the congestion cost is about 7.5% of the total cost. In comparison, in the NETCS report, the total cost of served load is about $171 billion and the congestion cost is about 4.7% of the total cost. That is, the total costs in two cases are almost the same but the POMS simulation results show more congestion. Fig. 15 shows the relationship between the congestion cost and the constrained transmission capacity for the POMS simulation in 2008 and 2018. For the 2008 case, 20% of the constrained transmission capacity accounts for about 73% of the total congestion cost and 50% of the constrained transmission capacities account for 97% of the total congestion cost. For the 2008 case in the NETCS report, 20% of the constrained transmission capacity accounts for 60% of the total congestion cost and 50% of the constrained transmission capacity accounts for 95% of the total congestion cost [2]. The POMS simulation results are similar to those of the NETCS in this case.

The POMS simulation results in Fig. 15 also show that the congestion cost is caused by a small number of constrained branches. The POMS results are similar to the NETCS results. Since the congestion cost is ultimately passed through to consumers, this also means that the planning of a relatively small number of transmission projects along constrained transmission paths could lead to a significant reduction in congestion costs and introduce a major economic benefit to consumers.
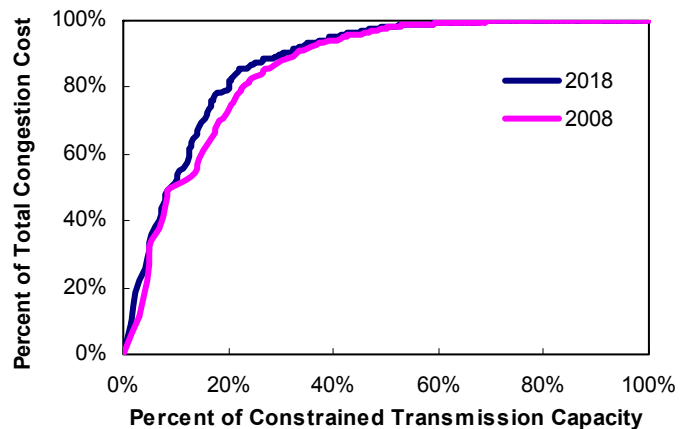

Fig. 15 Congestion Cost and the Constrained Transmission Capacity

E. Comparison of POMS Results in 2008 and 2018

In this section, we compare the POMS simulation results for 2008 and 2018.

E1) Locational Marginal Prices

Figs. 5 and 10 show that LMPs in 2018 are higher than those in 2008. In fact, the average load-weighted LMP in the Eastern Interconnection increases from $48.85/MWh in 2008 to $65.93/MWh in 2018. The higher LMPs could be attributed to increasing loads and fuel prices.

E2) Production and Congestion Costs

The total production cost in 2008 is about $75.3 billion as compared to $83.6 billion in 2018. The hourly production costs in 2018 (Fig. 11) and 2008 (Fig. 6) are similar. In both cases, higher production costs appear in the summer months (July and August). As expected, the hourly production costs in 2018 are higher than those in 2008 due to the load growth and fuel price escalations. Even though the New England and the Florida are not considered in the 2018 simulation, the total cost of served load increases from $172.3 billion in 2008

to $230.9 billion in 2018. It is interesting to note that the total cost of served load increases by 34% while the total production cost increases by 11%. This phenomenon can be explained using a two-bus example presented in Appendix C.

The congestion cost as a percentage of the cost of supplying the load increases from 7.5% in 2008 to 10% in 2018, which shows that the system is more congested in 2018 due to the load growth and higher fuel prices. The results would also point out that sufficient generation and transmission projects investments may not have been planned within the 10-year period.

Fig, 15 shows that the 2018 curve is a little higher than the 2008 curve, 20% of the congested transmission capacity accounts for about 73% of the total congestion cost in 2008 while 20% of the congested transmission capacity accounts for 83% of the total congestion cost in 2018. This means that congestion costs are more concentrated on a small percentage of constrained transmission capacity in 2018 than in 2008. Fig. 15 also shows that 50% of the congested transmission capacity accounts for 97% of the total congestion cost in 2008 and that 50% of the congested transmission capacity accounts for 98% of the total congestion cost in 2018. This means that the congestion cost is attributed to half of the congested capacity. In Fig. 15, the two curves almost coincide above the 50% of congested transmission capacity, which shows that the other 50% of the congested transmission capacity has very small impact on the congestion cost in both 2008 and 2018.

E3) Constrained Transmission Capacity as a Function of Time

Fig. 16 shows the percentage of constrained transmission capacity as a function of time. Fig. 17 shows the MW constrained transmission capacity as a function of time in 2018. In 2018, about 549GW of transmission capacity is congested, 4.9% of which is continuously congested and 66% is congested less than 20% of the time in one year. Based on the U90 metric, about 944GW of the transmission capacity is constrained, about 5.4% of which is constrained continuously in one year. In 2008, 228GW of transmission capacity is congested, about 11% of which is congested continuously for the entire year and 50% is congested less than 20% of the time in one year. Based on the U90 metric, about 588GW transmission capacity is constrained in 2008, about 15% of which is constrained continuously for the entire year.

In Fig. 16, the two curves are closer in comparison to Fig. 12. This means that the transmission capacities that are identified as constrained by the U90 metric would be more often constrained in 2018 than in 2008. In Fig. 16, the two curves coincide beyond the 40% constrained transmission capacity which account for about 15% of the time, so about 60% of constrained transmission capacity is constrained only in a few hours for the one year. Again we see that the congestion would be more confined to a small percentage of constrained transmission capacities in 2018 as compared with those in 2008.
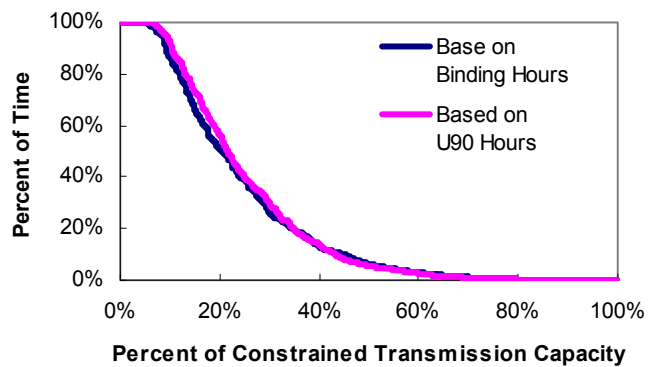

Fig. 16 Constrained Transmission Capacity as a Function of Time in 2018
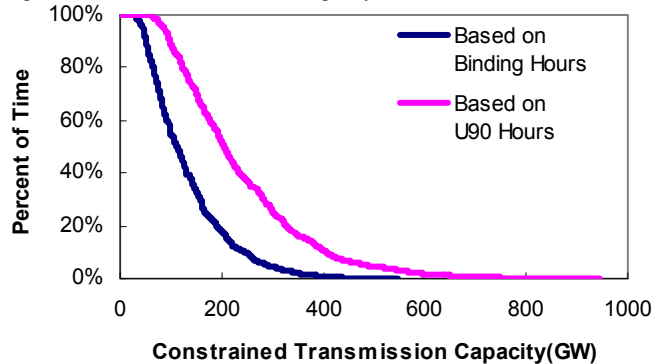

Fig. 17 Percent of Time and Constrained Transmission Capacity in 2018

III. CONCLUSIONS

In this paper, a SCUC methodology is proposed in POMS for the congestion analysis in the U.S. Eastern Interconnection for 2008 and 2018. The POMS simulation results are compared with those in the NETCS report. The simulation results are integrated with GIS data to offer a comprehensive and intuitive understanding of transmission constraints and LMPs. We envision that the proposed POMS methodology and the result can provide valuable information for transmission expansion studies.

APPENDIX

A. Congestion Metrics

In NETCS, five metrics were defined to assess the magnitude of transmission congestion, including binding hours, U90, all-hour shadow prices, binding hour shadow prices, and congestion rents. The metrics used in this paper include binding hours, U90 hours, constrained transmission capacity, LMPs, cost of served load, and congestion cost.

1) Binding Hours and U90 Hours

Those branches on which the flows have reached their limits are identified as congested branches. In addition, branches with flows above 90% of the flow limits are identified as U90 branches. In this paper, two congestion metrics including the binding hours and the U90 hours [2] [9] are defined as follows which are based on a long term (e.g., 8,760 hours) POMS simulation.

$$\text{Binding hours of branch } l = \sum_{t=1}^{NT} x_{l,t} \qquad (1)$$

$$x_{l,t} = \begin{cases} 1 \text{ if branch } l \text{ is congested at period } t \\ 0 \qquad\qquad\qquad\qquad \text{otherwise} \end{cases}$$

$$\text{U90 hours of branch } l = \sum_{t=1}^{NT} y_{l,t} \qquad (2)$$

$$y_{l,t} = \begin{cases} 1 \text{ if branch } l \text{ is loaded above 90\%} \\ \qquad\quad \text{of its capcity at period } t \\ 0 \qquad\qquad\qquad\qquad \text{otherrwise} \end{cases}$$

where *NT* represents the number of time periods (e.g., 8,760). These two definitions are similar to those in the NETCS report.

Similar to U90 hours, other metrics such as U75 hours or U60 hours can also be defined in order to assess the degree of congestion. These metrics can be used to classify and rank the identified congestions.

2) Constrained Transmission Capacity

The constrained transmission capacity of a system is the sum of the transmission capacity of all branches that are constrained at least in one hour during the study horizon. The constrained transmission capacity could be different when different congestion metrics are used, e.g., binding hours and U90 hours. If binding hours is applied to identify congestions, the constrained transmission capacity is formulated as follows.

$$\text{Constrained transmission capacity} = \sum_{l=1}^{NB} z_{l,1} * PL_{l,\max}$$

$$z_{l,1} = \begin{cases} 1 \text{ if binding hours of branch } l > 0 \\ 0 \text{ if binding hours of branch } l = 0 \end{cases} \qquad (3)$$

where *NB* represents the number of branches and $PL_{l,\max}$ is the capacity of branch *l*. Similarly, if U90 hours is applied to identify congestions, the constrained transmission capacity is formulated as follows.

$$\text{Constrained transmission capacity} = \sum_{l=1}^{NB} z_{l,2} * PL_{l,\max}$$

$$z_{l,2} = \begin{cases} 1 \text{ if U90 hours of branch } l > 0 \\ 0 \text{ if U90 hours of branch } l = 0 \end{cases} \qquad (4)$$

3) LMPs

LMPs at individual buses are calculated as part of the outputs from the SCUC based simulation. Since LMP differences in a system are caused by congestions, an LMP map would provide an intuitive way of visualizing congestions across the system. LMP information is not discussed in the NETCS report.

4) Cost of Served Load

The cost of served load is the total payment made by all loads in the system, which is calculated as,

$$\text{Cost of served load} = \sum_{t=1}^{NT} \sum_{j=1}^{ND} LMP_{j,t} * D_{j,t} \qquad (5)$$

where *ND* represents the number of load buses; $LMP_{j,t}$ represents the LMP of load bus *j* at period *t*; $D_{j,t}$ represents the load at bus *j* at period *t*.

5) Congestion Cost

The congestion cost was calculated as the increase in the production cost due to the re-scheduling of units to alleviate congestions [10]. In this paper, the congestion cost is defined as the difference between the load payment and the generation credit based on LMPs,

$$\begin{aligned} \text{Congestion cost} = \sum_{t=1}^{NT} \sum_{j=1}^{ND} LMP_{j,t} * D_{j,t} \\ - \sum_{t=1}^{NT} \sum_{i=1}^{NG} LMP_{i,t} * P_{i,t} \end{aligned} \qquad (6)$$

where *NG* represents the number of generator buses; $LMP_{i,t}$ represents the LMP at generator bus *i* at period *t*; $P_{i,t}$ represents the generation at bus *i* at period *t*.

The congestion cost metric defined as (6) is similar to the congestion rent defined in the NETCS report [2]. Congestion cost as a percentage of the cost of served load could indicate the magnitude of congestion of the entire system.

B. Congestion Analysis

The one-line diagram of a two-bus system with two generators and two loads is shown in Fig. 18. G1 and L1 are located at Bus 1 and G2 and L2 are located at Bus 2. The capacities for both generators are 800MW and the incremental cost is 10$/MWh for G1 and 20$/MWh for G2. L1 is 400MW and L2 is 600MW. Bus 1 and Bus 2 are connected through one transmission line with a capacity of 300MW. In the ideal case, G1 and G2 will be dispatched to 700MW and 300MW, respectively. The economic transaction between Bus 1 and Bus 2 will be 300MW. Accordingly, the flow on the line will be 300MW, which makes the line congested. However, if we intentionally limit the transaction between Bus 1 and Bus 2 to 100MW, there will be no congestion on the line. This shows that economic transactions could cause congestions that are not present without the economic transactions
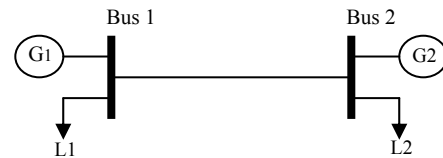

Fig. 18 Two-Bus System

C. Operation and Congestion Costs Analysis

The system is the same as the two-bus system in B. We assume the L1 is 250MW and L2 is 250MW at first. So the system will have no congestion. All the loads will be supplied by G1 and the production cost is $5,000 and the cost of served load is $5,000. If L1 and L2 are both increased by 50MW, the power flow on the transmission line will reach its limit 300MW). G2 will be the marginal generator at Bus 2 and the LMP at Bus 2 will be $20/MWh. The production cost

is $6,000, and the cost of served load is $9,000. That is, the production cost increases by about 20% and the cost of served load increases by about 80% owing to the growth of loads.

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