Smart Targeted Planning of VSC-Based Embedded HVDC via Line Shadow Price Weighting

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Abstract—In this paper, a novel approach to incorporate voltage source converter-based embedded HVDC for improving power system economic dispatch efficiency is proposed. An analytical formulation is presented to quantify the economic benefits of embedded HVDC by modeling its flow control as an injection-extraction pair in the economic dispatch of the transmission grid. A computationally efficient algorithm is proposed to rank the potential locations of such embedded HVDC. The algorithm is based on expected economic dispatch cost reduction weighted by the historical line shadow prices. The use of a distribution of historical data as a means of weighting also allows for incorporation of diurnal and seasonal influences on congestion patterns. Numerical case studies using the proposed method of locating the embedded HVDC suggest promising results in choosing the location of improved flow control devices.

Index Terms—Mixed ac/dc, security-constrained economic dispatch (SCED), transmission planning, voltage source converter (VSC) HVDC, wind curtailment.

NOMENCLATURE

Constants

\[ P_{Di}, \quad P_{Gi} \]
Real-power demand of load \(i\).
Real-power dispatch of generator \(i\).

Parameters

\[ b, \quad b_{ij}, \quad \bar{b}_{ij}, \quad B_R, \quad C_{Gi}, \quad H, \quad X_{ij}, \quad Z_{ij} \]
Vector of all system line susceptances.
Line susceptance between bus \(i\) and \(j\).
Reduced susceptance matrix.
Cost function of generator \(i\).
Distribution factor matrix.
Line reactance between bus \(i\) and \(j\).
Line impedance between bus \(i\) and \(j\).

Sets

\[ A, \quad a, \quad B, \quad D, \quad G, \quad L, \quad P_{L,P} \]
Reduced incidence matrix.
Incidence matrix.
# of buses.
Set of all loads.
Set of all generators.
# of lines.
Matrix of all possible injection-extraction pairs via existing lines.

Variables

\[ \Delta C_{\text{tot}}, \quad \Delta C_{\text{TOT}}, \quad \Delta C_{\text{TOT, int}} \]
Dispatch cost change from flow control on one line.
Dispatch cost change from flow control on all lines, individually.
Dispatch cost change from flow control on all lines, individually, per interval.

\[ \Delta F_f, \quad \Delta F_F \]
Vector of flexible capacity due to flow control on one line.
Vector of flexible capacity due to flow control on all lines, individually.

\[ \mu, \quad \mu_{\text{int}} \]
Shadow price vector from previous dispatch.
Shadow price vector from previous dispatch, for a particular interval.

\[ \theta_i, \quad \theta_{ij} \]
Bus \(i\) and \(j\) voltage angle difference.
Bus \(i\) and \(j\) angle difference.

\[ C_{\text{ED}} \]
Economic dispatch cost.

\[ F, \quad F_{ij}, \quad P, \quad P_{D,dc}, \quad P_E, \quad P_{\text{EXT}}, \quad P_{G,dc}, \quad P_{ij}, \quad P_f, \quad P_{\text{INJ}} \]
Matrix of all system line flows.
Real-power flow from bus \(i\) to bus \(j\).
Vector of real-power injection.
Scalar value of dispatched dc injection.
Scalar value of real-power extracted.
Flow control real-power extraction vector.
Scalar value of dispatched dc injection.
Real-power flow from bus \(i\) to bus \(j\).
Scalar value of real power injected.
Flow control real-power injection vector.
Scalar value of reactive power extracted.
Scalar value of reactive power injected.

\[ S_{ij}, \quad V_i, \quad V_j \]
Complex power flow from bus \(i\) to bus \(j\).
Complex voltage at bus \(i\).
Complex voltage at bus \(j\).

I. INTRODUCTION

This paper is motivated by the need for better transmission planning algorithms that address new planning objectives, incorporate new flexible transmission devices and do so in a more computationally efficient manner.

The objective of transmission planning has changed over the long history of electrical power system development in the United States. The earliest planning objective was to simply increased access as illustrated by early papers focused on nuances of subtransmission that could provide increased access [1], [2]. In the 1970s, optimization techniques were applied to transmission planning that helped to weigh competing interests of functionality and construction costs [3], [4].
The cost of transmission losses were included in the 1980s as was the consideration of net present value of costs and benefits [5]–[7]. More recently, even more complex cost objective functions were added that included reliability-based value. Reference [8] values this reliability as unserved energy costs. It is valued similarly in [9] in that the reliability is considered as customer outage costs. Chowdhury and Koval [10] took a previously unconsidered approach and valued the reliability component using customer survey results.

The most recent transmission planning objectives have been in quantifying and including the value of transmission planning results that come from effects seen in competitive markets [11]. This has also been driven by policy implementations such as the Federal Energy Regulatory Commission (FERC) Order 1000 [12]. The norm before this order was to have a socialized cost approach to funding for transmission projects [13]. In many systems, these socialized costs were shared by generators or loads or a combination of the two collective entities. FERC Order 1000 mandates, among other things, that transmission planners quantify which entities benefit economically from transmission projects. It also mandates project costs be allocated to entities that benefit in proportion to how much they benefit.

The Electric Reliability Council of Texas (ERCOT) now has a pathway for transmission planning justification-based solely on economic criteria [14], which is becoming an industry trend.

Even though the objective has evolved, one thing has been consistent, these approaches have been optimization based. Methods have combined linear programming, dynamic programming, mixed integer programming, and heuristics. Although these methods have been continually advanced, they are all still limited by computational burden when applied to large systems.

Also recently, as flexible transmission devices like flexible ac transmission systems (FACTS) devices and HVDC have become realistic transmission planning alternatives to more wires and capacitor backs, transmission planning methods are moving to include them. Lu et al. [15] incorporated optimal FACTS device sizing and location for reactive power planning. Kuruganty and Woodford [16] include line commutate converters-based HVDC in reliability-based transmission planning. These approaches are revisiting different objectives while including new device choices.

Several observations emerge from the preceding discussion that motivate the work in this paper.

1) The transmission planning objective has evolved and it must now include economic impacts in competitive markets.

2) The optimization approaches in the mentioned literature suffer from computational burden.

3) Transmission planning methods must now also include flexible transmission devices as they are becoming viable and sometimes necessary alternatives.

The smart targeted planning (STP) method proposed in this paper centers its objective on economic impacts, which as discussed, is the newest of the objectives in transmission planning. STP also focuses on a flexible transmission device, the voltage source converter (VSC)-based embedded HVDC system, which has been receiving much more attention in recent literature. Most importantly, the proposed algorithm uses a nonoptimization based method and therefore does not suffer from computational burden.

The paper is organized as follows. In Section II, the foundation for the STP algorithm is formulated. In Section III, the STP algorithm is presented based on the dc load flow approximation which results in the distribution factor matrix. From this an equation for flexible line system capacity (FLSC) is derived. This is weighted by historical shadow price information to produce an expected net system dispatch cost change. Section IV provides the results and analysis of the numerical testing on an ERCOT simplified 24-bus system and the IEEE 118-bus system. Concluding remarks and future work are suggested in Section V.

II. PROBLEM FORMULATION

A. DC Power Flow Approximation

The problem formulation is similar to that in [17]. Fig. 1 shows the classic two bus system. The complex power flow for this system is described as the following:

\[ S_{ij} = V_{i}I_{ij}^{*} = V_{i} \left( \frac{V_{j} - V_{i}}{Z_{ij}} \right)^{*}. \] (1)

Under the assumption that:
1) Lines are lossless.
2) Voltage magnitudes at all buses are around 1 per unit.
3) Phase angle difference between buses are relatively small, the nonlinear power flow equation can be linearized as the dc power flow

\[ F = \text{diag}(b) \cdot A^T \cdot \theta. \] (2)

The vector of real-power injections and the dc power flow is related by the following equation:

\[ F = \text{diag}(b) \cdot A^T \cdot B_{R}^{-1} \cdot P. \] (3)

The compact matrix form of the equation is

\[ F = H \cdot P. \] (4)

B. SCED Formulation

The security constrained economic dispatch (SCED) problem is formulated as a linear optimization as shown below

\[ C_{ED} = \min \sum_{i \in G} C_{Gi}(P_{Gi}) \] (5)

s.t.

\[ P_{Gi}^{\min} \leq P_{Gi} \leq P_{Gi}^{\max} \] (6)

\[ P_{Li}^{\min} \leq P_{Li} \leq P_{Li}^{\max} \] (7)

\[ \sum P_{Gi} = \sum P_{Di}. \] (8)
The objective is to minimize the cost of real power produced with respect to the cost functions of each generator. The cost functions used are constant marginal cost functions. Since it is a dispatch problem the set of generators committed for dispatch is assumed fixed. Start up and shut down costs are not considered. The optimization is subject to the equality constraint of real-power balance. The optimization is also subject to several inequality constraints such as the real-power minimums and maximums of each generator and the real-power flow limits of each line.

C. VSC Model

For this paper a VSC-based HVDC link will be the fundamental unit of flow control that will be incorporated in the dc optimal power flow-based SCED. The VSC converter will be treated as a black box similar to that discussed in [18]. Fig. 2 shows a diagram of the black box VSC with respect to real-power flow used in [18]. The VSC converter produces an ac voltage waveform at $U_{conv}$. If this waveform is considered in the same way as a voltage source generator the interaction of $U_{conv}$ to $U_L$ is similar to that of the two bus system described in Section II. This means that real-power flow from the VSC converter can be described as

$$P_{conv} = \frac{U_{conv} U_L \sin(\theta_{conv,L})}{X_{conv}}. \quad (9)$$

If the same lossless dc approximation is applied, where it is assumed that $U_{conv} \cong U_L \cong 1$ and $\theta_{conv,L}$ is small, $P_{conv}$ becomes

$$P_{conv} = b_{conv} \cdot \theta_{conv,L}. \quad (10)$$

The angle, $\theta_{conv,L}$, is controllable by the VSC converter and thus so is $P_{conv}$. The control strategy of the VSC-HVDC link is real-power flow control. The link is considered a lossless line so the real-power injected at the converter in inverter mode is equal to the real power extracted by the converter acting in rectifier mode but with opposite sign at all times as shown in

$$P_I = -P_E. \quad (11)$$

Fig. 3 shows a diagram of the black box VSC with respect to reactive power flow used in [18]. The equation for $Q_{conv}$, shown in Fig. 3 can be developed in a similar fashion from the two bus system in Section II as

$$Q_{conv} = \frac{U_{conv} U_L \cos(\theta_{conv,L})}{X_{conv}} - \frac{U_{conv}^2}{X_{conv}}. \quad (12)$$

If the same lossless dc approximation is applied, where it is assumed that $U_{conv} \cong U_L \cong 1$ and $\theta_{conv,L}$ is small, $Q_{conv}$ becomes

$$Q_{conv} = 0. \quad (13)$$

III. SMART TARGETED PLANNING

A. Flexible Line System Capacity

The addition of a controllable flow element like a VSC HVDC link can be used as a means to control flow patterns on the existing ac system. The change in flow patterns due to the controllable flow of the HVDC link can be considered as flexible line capacity for each affected line. The system effect is termed FLSC.

For a system in a given dispatch state, the flow on each line in the system is described in (4). The presence of the HVDC link does not affect the distribution factor matrix, $H$. The real-power injection vector $P$ is changed by the controlled flow of the HVDC link. The following vectors represent this change:

$$P_{INJ} = \begin{bmatrix} 0 \\ P_I \\ \vdots \\ 0 \end{bmatrix}, P_{EXT} = \begin{bmatrix} 0 \\ P_E \end{bmatrix} \text{ where, } P_I = -P_E. \quad (16)$$

So, the change in flow due to the flow on the HVDC link is as follows:

$$\Delta F_f = H \cdot (P_{INJ} + P_{EXT}). \quad (17)$$

Equation (17) defines FLSC, a flexible capacity that can be utilized in each dispatch to relax the line flow constraints optimally in each interval.

To investigate the FLSC for all possible existing connections a matrix of injection-extraction pairs can be used in place of the singular column vector used in (17). The reduced incidence matrix of the system is just this matrix of all possible existing connections. So (17) becomes

$$\Delta F_f = H \cdot P_{L,P} \text{ where, } P_{L,P} = A. \quad (18)$$

B. Historical Shadow Price Weighting

To result in a market impact the FLSC can be seen as a tool to provide a set of possible solutions around a historical operating point that is still within constraints. The set is then
weighted by the sensitivity metric of shadow prices to arrive at a system dispatch cost delta provided by the FLSC attributable to the flow control upgrade in question. The vector $\mu$, is the shadow price vector which is a result of the original dispatch. It signifies the expected change in dispatch cost to a change in a constraint. The portion of this vector that corresponds to line flow constraints is the shadow price vector for transmission lines. It can be used to weight the FLSC to quantify the effect the HVDC line flow has on system dispatch cost as shown below

$$\Delta C_{\text{tot}} = \mu \cdot \Delta F_{f}. \quad (19)$$

Equation (19) can be augmented using (18) to give the vector $\Delta C_{\text{TOT,int}}$ in (20), which represents the cost delta due to the added FLSC for all branches in the system for a particular interval

$$\Delta C_{\text{TOT,int}} = \mu_{\text{int}} \cdot \Delta F_{F}. \quad (20)$$

The shadow price of a particular interval fully describes the value to the system for the full duration of the interval, but it cannot describe the value outside of that binding duration. Shadow prices for each interval must be applied only to that interval. Diurnal and seasonal patterns will produce differing shadow prices which will in turn produce differing cost deltas. To account for that, the vector $\Delta C_{\text{TOT,int}}$ should be summed for all intervals in the year producing $\Delta C_{\text{TOT, yr}}$

$$\Delta C_{\text{TOT, yr}} = \sum_{k=1}^{T} \Delta C_{\text{TOT,k}}. \quad (21)$$

Equation (21) yields a vector of cost deltas due to FLSC taking into account diurnal and seasonal patterns. The larger the cost delta is the larger the market impact will be. This vector can then be sorted to provide the upgrade candidates with the maximum market impact.

C. Application of Smart Targeted Planning

The STP method begins with a dispatch result which will provide the dispatch cost and the shadow price vector, $\mu$. This means that for whatever the planning horizon is, one year, five years, ten years, etc., an initial dispatch must be run that does not include the VSC-based embedded HVDC line. The STP method is applied to the information from this original dispatch and a set of predicted cost decreases for each year in the planning horizon, $\Delta C_{\text{TOT, yr}}$, is produced. The highest decrease values from this set will point to a candidate set for a redispach of the system. This redispach would include the HVDC line and would be run for the whole planning horizon.

The straight forward alternative to the STP method for locating the HVDC line addition is through an exhaustive heuristic search (EHS). This means a dispatch for the planning horizon (one, five, ten years, etc.) would be completed for each possible location. This is computationally very expensive for long-term planning issues. Thus, intuition and experience would be used to produce a candidate set for trials which is not quite thorough and may miss better nonintuitive options. All these reasons speak to the key advantage of the STP method.

D. Multiterminal VSC-Based Embedded HVDC Systems

Multiterminal VSC-based embedded HVDC systems are a logical extension of the single line two terminal system discussed in this paper. Recent projects in the United States such as the Mid-Atlantic Power Pathway Project, the Champlain Hudson Power Express Project, and the Tres Amigas Project are of the multiterminal structure [19], [20]. With the exception of the Tres Amigas, these projects are also embedded systems. Although many of the current systems of this configuration are driven by technical necessity, the economic impact is important in micro-siting. It is also possible that with advancement in planning techniques that include devices like VSC-based embedded HVDC, like the STP method, that more projects will be identified with economic drivers that are stronger than their technical drivers. The STP method is easily generalizable to include multiterminal VSC-based embedded HVDC systems. When multiterminals are considered (16) becomes (22) and (23)

$$P_A = \begin{bmatrix} 0 \\ P_a \\ \vdots \\ P_c \\ 0 \end{bmatrix}, P_B = \begin{bmatrix} 0 \\ 0 \\ \vdots \\ 0 \end{bmatrix}, P_C = \begin{bmatrix} 0 \\ 0 \\ \vdots \\ 0 \end{bmatrix}, \quad \ldots \quad (22)$$

where

$$0 = P_a + P_b + P_c \ldots \quad (23)$$

The rest of the STP method derivation follows in the same way as with the two terminal system. The application in the planning process is also the same.

E. Smart Targeted Planning With Converter Losses

A key advantage of the STP method is built in to how it weights the flexible line capacity provided by the VSC-based embedded HVDC system. The shadow price holds information pertinent to all aspects included in the base dispatch. This means that although in this paper a simple SCED formulation is utilized, a SCED formulation that includes more complex aspects in either the objective function or constraints can be easily substituted and the STP method will still perform as expected. Effects of the inclusion of complex aspects such as line losses, ramp constraints, and others will be represented in the shadow prices used to weight the flexible line capacity. So in general, as long as the complexity of a SCED formulation is represented in the base dispatch, the STP method will be able to account for its effects in the results.

One aspect that would not be available in the base dispatch is the impact of losses in the converters. While early technology used in VSC-based embedded HVDC systems had significant losses on the order of 3% to 4% [21], recent technologies show losses in converter stations of less than 1% [22]. This means that for the full power transfer that includes all associated converter stations the total losses are on the order of system line losses. Thus, if a simplification of a lossless system is used, this too can be applied to the losses by the VSC-based embedded HVDC system. If losses are to be included in the rest of the system they must also be included.
for the VSC-based embedded HVDC system and thus the STP must be augmented slightly to account for them.

To account for conversion losses (19) becomes

$$\Delta C_{\text{tot}} = \begin{cases} 
\mu \cdot \Delta F_f - \lambda^T |a| \text{LF} : \mu \cdot \Delta F_f > \lambda^T |a| \text{LF} \\
\mu \cdot \Delta F_f \leq \lambda^T |a| \text{LF}.
\end{cases}$$

(24)

The term $\lambda^T |a| \text{LF}$ in (24) represents the cost of losses modeled as additional load at the terminal priced at the locational marginal pricing (LMP) at the bus the terminal is connected to. This is achieved by using the full incidence matrix, $a$, weighted by the loss factor, LF, at a price represented by the LMP vector, $\lambda$.

Subsequently, (20) and (21) change accordingly.

IV. NUMERICAL EXAMPLES

A. ERCOT Modeled 24-Bus System

1) Transmission Grid: In [23], a 24-bus system modeled after the ERCOT transmission system, first introduced in [24], is utilized. This system will again be utilized and is shown in Fig. 4. The system has 24-buses and 32 single line branches. It is divided into four zones representing the old North, South, West, and Houston zones in the zonal system pre 2010. The zones are connected by eight interzonal single line branches. Five of the eight interzonal lines have line limits. Since the original use for this system was an investigation on interzonal congestion all other lines except these five have no line limits. The flow patterns of the system are modeled off of the ERCOT published interzonal shift factors.

2) Load and Generation: The generation capacity, type, and zonal location are also modeled after published data [25] and represented by 13 generators, three of which are wind generators. The load zone amounts and locations are modeled after a “typical” day and include a diurnal pattern. The typical day is characterized by its peak load of 60,000 MW. To extrapolate this load pattern for a yearlong study, the weekly load percentage given in the description of the IEEE RTS 96 [26] is used to scale the load pattern. It is reproduced in Table I. These 52-week data points are then combined to create 12 typical monthly diurnal load profiles. For instance, the typical day has a peak load which is 88% of ERCOTs system high [27]. This would correspond to week 30 in [26, Table II] which is averaged with the values of weeks 26 through 29 to produce the typical day for the month of March. Every other month is scaled accordingly. Simulations on typical days for all 52 weeks were contemplated but although the STP algorithm runs very quickly, the EHS trials take prohibitively long to run. This method of scaling to produce typical days allows for a very good, though not perfect, approximation of both diurnal and seasonal load patterns.

3) Analysis: Fig. 5 compares the results of the EHS versus the results of the STP. Some lines show large decreases in dispatch cost like lines 18 and 27 while others show very little dispatch cost decrease like lines 12 and 26. Even though the absolute numbers differ, both the STP and EHS methods produce sets of lines that begin to separate in terms of their impact on system dispatch cost. One way to look at the results would be to group the sets according to their dispatch cost impact. For instance, if an upgrade is only feasible with a yearly payback of above $500,000 then the set would consist of 13–15, 17, 18, 22, 24, and 27. If the threshold were instead $1,000,000, then the candidate set would be 17, 18, 24, and 27. EHS would take an immense amount of time to produce these candidate sets. On the other hand STP, using historical data already produced, could quickly and easily provide these candidates sets which would then be investigated more thoroughly. For the results, no particular threshold is called for.
for so the top ten cost decrease candidates will be analyzed closer.

The top ten line candidates that produce the greatest dispatch cost decrease are presented in Table II. It is important to see that both the EHS and STP methods produced the same top ten candidates for flow control.

Intuition would suggest that the flow control upgrade should come on a congested corridor line. The congested corridor lines in this system are 5, 9, 17, 18, and 24. Contrary to intuition Table II shows that line 27 which is not in the set of corridor lines is the second most effective upgrade. Also contrary to intuition, corridor line 5 is not even in the top ten whereas lines not in the congested corridor list such as 15, 22, 14, 13, and 7 together with line 27 as mentioned before, round out the top ten.

4) STP and EHS Result Differences: As seen in both Fig. 5 and Table II, the STP method does not produce the exact same absolute results as the EHS method. Both the STP and EHS methods agree that the largest decrease in dispatch cost will come from a flow control upgrade of line 18. The difference between the result from STP and the result from EHS is about 12%. The other top ten candidates have a difference ranging from 6.58% to 1.25%. This is an acceptable error during a preplanning period where a set of candidates is more important than an exact dispatch cost decrease.

Figs. 6 and 7 show the same information as Fig. 5 for January and July. In January, discrepancies exist between the results of the STP and EHS methods for a number of lines but no difference is more pronounced than that for line 18. The difference is over 100%. Conversely in July, there is exactly no difference in the results from the STP and EHS methods for any lines in the system.

The STP method is based on the sensitivity metric of shadow pricing of line constraints. In the dc approximated line flow paradigm, the FLSC is constant and continuous. The shadow pricing on the other hand is constant only as long as the constraint is active. For lines that are constrained before the flow control upgrade is considered and are still constrained after the upgrade, the resulting dispatch cost decrease will be the same for the STP and EHS methods. It is when a constrained line becomes unconstrained post upgrade and the shadow price goes from a nonzero value to zero that the STP and EHS begin to diverge. The opposite is also true, in that if a line is uncongested preupgrade but becomes congested post-upgrade the STP and EHS methods will diverge due to the discontinuous step change of the shadow price from zero to a nonzero number. In July, the load is sufficiently high that although the upgrade provides congestion relief that decreases dispatch cost the active constraint set does not change. In January, the active constraint set does change which leads to the divergence in the results of the STP and EHS methods described.

Although the STP method does not produce the exact same results for dispatch cost decrease as the EHS method, the STP does produce results close enough to provide a set of candidate lines for further investigation. As discussed before, it is the candidate set that is most important in the early points of transmission planning because various other system impact
studies must also be performed. An investigation into actual site construction upgrade costs must also be performed. It is only feasible to do these types of further due diligence on a set of upgrade options you have confidence will have an expected market impact.

5) Ten Year Planning Horizon: A planning tool like the STP method must be viable for multiple years in the planning horizon. To illustrate the viability of the STP method in multiple planning years a 10 year study based on the 24-bus ERCOT modeled system is performed. To create the system for a ten year horizon, the load is scaled based off the ten year long-term forecast published by ERCOT [28]. The peak values forecasted are used as indicators of overall growth. The base year used is 2013 from the report and all loads in the simulation are scaled proportionally to the increase in peak load. In year four of the simulation, generation is increased by 10% in order to account for load growth and provide enough generation in the peak times of the year. Also, wind capacity in the simulation is increased by 2% per year. The same process is used to produce Fig. 8 as is used to produce Fig. 5.

From Fig. 8, it can be seen that in the remaining years of the 10 year horizon the STP method performs very well compared to the EHS method. In fact, it seems to perform even better than in the one year horizon. Most importantly, the candidate set produced by the STP method is the same as that produced by the EHS method. It is an accurate candidate set that is most crucial for the rest of the planning process.

B. IEEE 118-Bus System

1) Transmission Grid: A modified IEEE 118-bus system, shown in Fig. 9 is adapted from [29] for testing. The system consists of 3 zones, 118-buses, 179 single line branches, 54 generators, and 91 loads. Each line has its own line limit but in the base case none were active constraints so all interzonal lines (line numbers 44, 45, 54, 104, 112, 116, 178, 123, 141, 151, and 152) had their respective limits reduced to 90 MW. The optimal power flow model used for testing is a lossless model so only the reactance values of the lines shown in [29, Table III] are used. Transformer tap data in [29, Table IV] is ignored.

2) Generation and Load: Generation capacity, cost, and location were described in [29] and have not been modified except that the cost structure used in the dispatch trials only consider the marginal per MW cost. A diurnal hourly load pattern is used as a typical day. It too is provided in [29]. This is also extrapolated in the same way as was done with the 24-bus system to produce 12 typical load patterns for testing. One difference is that the typical day is considered 85% of the yearly peak. Ancillary service reserve and dispatch data in [29, Tables V and VII] are not used for testing.

3) Analysis: Fig. 10 shows the annual dispatch cost decrease for STP and EHS trials on all 179 lines in the 118-bus system. It can be seen that the majority of lines do not have significant impact on dispatch cost when flow control is employed. As in the results for the 24-bus system a set of lines with significant impact begins to emerge. In the 24-bus system nearly one-third of the lines show significant impact whereas in the 118-bus system the percentage of lines showing significant impact is much lower. It must be noted that the amount of dispatch cost decrease is lower in the 118-bus system than in the 24-bus system. This is due mostly to difference in peak loading. Although the 118-bus system has more buses it has about a tenth of the peak load. The other factors
include the differing cost functions in the two systems. The 118-bus system only contains conventional units whose lowest marginal cost function is around $8 whereas the 24-bus system includes wind resources with negative marginal cost as low as $-16.

Fig. 11 and Table III show the STP and EHS results for the 10 lines in the 118-bus system that produced the largest system dispatch cost decreases. The STP and EHS methods produce almost identical results with only small discrepancies in a few lines. Table III shows that even for the highest performing candidate the STP method only produces a 2.57% difference in dispatch cost decrease versus the EHS method. Seven of the top ten candidates show a less than 1% difference between the two methods. But more importantly, as in the 24-bus system trials, both methods produce the same top performing candidate list. This list can then have other tests performed on them as necessary. It can also be seen that some intuitive candidates like those in the list of congested lines show large benefits from flow control but so do some uncongested lines. In total, the 118-bus system has 11 congested corridor lines. In the top ten lines only five are of the congested line set while the other five are not. This agrees with the findings in the trials performed on the 24-bus system in that the STP method can find both the intuitive and nonintuitive high performing candidates.

C. Computational Advantages of STP Method

Decreased computation time is a major advantage for the STP method versus the EHS method. The STP method only needs one base dispatch result per interval in the planning horizon to produce the candidate list. The EHS method needs a dispatch per interval per possible line upgrade. The computation statistics for the 24-bus system and 118-bus system presented earlier are assembled in Table IV. In the numerical trials for this paper only one typical day is used to represent a month. Each of the typical days has 24 intervals (1 h per interval). So for the numerical trials, the number of intervals dispatched is 288 as shown in Table IV.

The total time needed for the numerical trials on the 24-bus system using the STP method is 103 s. If that were scaled to a full year number (instead of a typical day per month) the time needed would be 0.87 h. Using the EHS method on the 24-bus system, the time needed is 3796 s or 63.3 min. Scaled to a full year, the time needed would be 32 h. For the 118-bus system, the time needed for the STP method is 494 s or 8.2 min. The scaled number is 4.17 h. For the EHS method on the 118-bus system, the needed computation time is 27.2 h and when scaled it is 827.8 h. All simulations were
VSC-based embedded HVDC system would not be dispatched. The predicted dispatch cost decrease by the STP method is compared to an EHS of all possible line upgrades in an ERCOT-equivalent 24-bus system and in an IEEE 118-bus system.

In simulations on both systems, the much quicker STP algorithm predicted absolute values for dispatch cost decrease very similar to that found by the time intensive EHS. More importantly, the STP method suggests the same top ten candidates for line upgrades, many of which were nonintuitive choices.

Future work will expand this line of research in STP to include other flow control devices. The focus will then move to incorporate advanced devices like VSC-HVDC and FACTS controllers into other times scales that may affect SCED and provide not only system reliability and stability benefits but also monetary benefits via further dispatch cost decrease. Lastly, recommendations will be provided for operation and policy regimes that will increase potential incorporation of these devices in such manners.

D. Numerical Trials With Converter Losses

Numerical trials on the ERCOT modeled 24-bus system are repeated. In this set of trials, the converter losses are included in the SCED formulation used by the EHS. The equations developed in Section III-E are used for the application of the STP method. The comparison of the results from the EHS and STP methods is shown in Fig. 12.

It can be seen that the STP method with converter losses performs with similar precision as the STP method that does not consider losses. The absolute values of the dispatch cost decrease are lower, as can be expected, because the cost of losses in the converters is included. Also noteworthy is that many lines no longer have nonzero values for dispatch cost decrease. This is because the cost of losses from the converters due to flow through the VSC-based embedded HVDC system is higher than the possible benefits. In these scenarios, the VSC-based embedded HVDC system would not be dispatched.

V. Conclusion

In this paper, a ranking algorithm of prioritizing the incorporation of VSC-based HVDC transmission line for improved economic dispatch is proposed. This algorithm, termed as STP, proposes a line shadow price-based weighting approach to ranking the potential economic impact of incorporating a new VSC-based HVDC link along existing transmission lines.

REFERENCES


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