Investigating the Impacts of Distributed Generation on Transmission Expansion Cost: An Australian Case Study

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Abstract

Distributed generation (DG) is rapidly increasing its penetration level in Australia, and is expected to play a more important role in the power industry. An important benefit of DG is its ability to defer transmission investments. In this paper, a simulation model is implemented to conduct quantitative analysis on the effect of DG on transmission investment deferral. The transmission expansion model is formulated as a multi-objective optimization problem with comprehensive technical constraints, such as AC power flow and system security. The model is then applied to study the Queensland electricity market in Australia. Simulation results show that, DG does show the ability to reduce transmission investments. This ability however is greatly influenced by a number of factors, such as the locations of DG, the network topology, and the power system technical constraints.

I. INTRODUCTION

In its beginning period, the electricity industry consisted of generation units that are deployed dispersed and have no interconnection. The situation soon evolved, and by 1930s centralized operation became the dominant feature of the industry, because of the significant economies of scale and technical advantages. Nowadays, the power industry is still characterized by large-scale centralized generation and an extensive transmission and distribution infrastructure. However, this centralized power generation model has been challenged in recent years. The large-scale base load generators are frequently criticized by their environmental damages. Moreover, along with the continuously increasing sizes and complexities, the security of power transmission/distribution networks is also questioned by critics. Taking into account the concerns above, distributed generation (DG) technologies are expected to play a more important role in the electricity industry.

Distributed generation can be defined as the generation units that are connected at the distribution network level and close to end-users [Ackermann, 2001]. Based on this definition, DG is not necessarily green power generation. However, the renewable DG technologies (wind turbine, solar photovoltaic, biomass, etc) are more preferred options due to their environmental benefits. Another important benefit claimed by the proponents of DG is that it potentially can defer investments in the transmission/distribution infrastructure. However, only a few studies [Borenstein, 2008; Kahn, 2008; Beach, 2008] have been conducted to investigate how significant the effect of T&D investment deferral can be. Moreover, existing studies usually ignore system technical constraints, which essentially have great impacts on their study results.

In this paper, we implement a simulation model to investigate the impacts of distributed wind and solar generation on transmission network expansion costs. In this study, the transmission expansion problem is modeled as a cost minimization problem subject to system reliability and AC power flow constraints. Generation investments will be implemented based on the nodal prices obtained in power flow studies. Strong policy incentives are assumed to support the large-scale deployment of DG. More specifically, power system security constraints are also carefully considered in our model. The model is then applied on the Queensland electricity market in Australia to study the true impact of DG on transmission investments.

The rest of this paper is organized as follows: a review of relevant research is provided in Section II. In Section III, the proposed model for simulating transmission expansion behaviors is discussed in detail. The transmission expansion is formulated as a multi-objective optimization problem. The technical constraints, including AC power flow, voltage stability and transient stability, are also discussed. The areas of influence method is then introduced to determine what portion of transmission investments is caused by DG. The simulation results are provided in Section IV. Finally in Section V, we present the conclusion.

II. REVIEW OF RELEVANT RESEARCH

Distributed generation is a hot research topic and rapid progresses have been made in recent years. Research has been firstly devoted to the definition and classification of DG [Ackermann, 2001; Carley, 2009]. Although rigorously speaking DG can be either renewable or non-renewable, in this paper we focus on renewable DG technologies only. Therefore we use ñdistributed generationò and ñrenewable distributed generationò inter-changeably.

Since the market penetration of DG is still low in most countries, a number of studies [Dondi, 2002; Johnston, 2005] have been conducted to investigate the barriers for DG penetration and the factors that can contribute to DG deployment. A number of economic analyses [Gulli, 2006; Abu-Sharkh, 2006] have also been conducted to study the market performance of DG systems. In addition, since DG is usually connected at the distribution level, extensive research [Haffner, 2009; Sharma, 1997; Ball, 1997] has been conducted to investigate the impacts of DG on distribution network planning. These studies usually focus on determining the optimal sizes and locations of DG units in the distribution network from the distribution companyôs point of view. Other studies studies [Neto, 2006; Zhu, 2006] also have been performed to understand the impacts of DG on the system side, such as on reliability, system security and power quality.

The high costs of wind and solar generation are the most important barriers for their market penetration. Till 2006, the capital cost of wind power is still 4 times higher than coal-fire power in Australia [Wibberley, 2006]. The capital cost of solar PV is even higher. However, considering only the cost of DG may not give a comprehensive picture of the problem, since a number of other benefits of DG, such as the environmental benefits and reduced transmission losses, may have been neglected. Another frequently mentioned benefit of DG is its potential effect on deferring transmission network investments. Researchers however have not reached an agreement about whether this deferral effect is significant. The study conducted in [Borenstein, 2008] concludes that, the PV systems in California have no significant effect on reducing transmission investments, and are unlikely to have the deferral effect in other areas, due to the fact that PV systems are not specifically deployed in transmission-constrained areas. This study however has been challenged by the proponents of solar PV [Kahn, 2008; Beach, 2008]. Studies have also been conducted to investigate the impacts of wind power on transmission expansion costs [Dale, 2004]. A common problem of these studies is that many technical constraints of the power system, especially the security constraints, are ignored. These simplifications potentially may bias the study results.

Transmission network expansion has been widely studied in existing literatures. Before the market deregulation, transmission network expansion is conducted sorely by the power utility and is usually modeled as an optimization problem that aims at minimizing expansion investments subject to system reliability and other technical constraints [Zhao, 2007]. Market deregulation has changed the nature of the power industry. In a market environment, transmission network expansion may also involve other objectives, such as enhancing market competition, minimizing network congestion and facilitating the integration of renewable energy sources [Buygi, 2006]. A number of technical constraints should be carefully modeled in transmission expansion models. The most fundamental ones are power flow [Zhao, 2009] constraints, which represent the physical laws transmission systems must obey. System security constraints [de.J. Silva, 2005] are also essential, since violating security constraints potentially can cause large scale blackouts and thus incur huge economic and social damages. The above models can be combined with a generation investment model to form a long-term market simulation tool. Given projected power demands and generation investments, the transmission expansion model can be used to simulate the investment behaviors of a transmission network operator.

After the optimization objectives and constraints are formulated, transmission network expansion problem can be solved by applying different optimization techniques to obtain appropriate expansion plans. The optimization techniques can be further classified into two types: mathematical optimization and heuristic optimization. The mathematical optimization models find an optimum expansion plan by using a calculation procedure that solves a mathematical formulation of the transmission expansion problem. This approach includes linear programming [chanda, 1994], dynamic programming [Dusonchet, 1973], nonlinear programming [Youssef, 1989], mixed-integer programming [Bahiense, 2001] and benders [Binato, 2001]. In Contrast heuristic methods select optimum expansion plans by performing local searches with the guidance of some logical or empirical rules [Latorre, 2003]. Heuristic optimization techniques that have been applied to solve the transmission expansion problem include genetic algorithms [da Silva, 2000], simulated annealing [Gallego, 1997], differential evolution [Zhao, 2009] and the TS algorithm [da Silva, 2001].

To quantitatively measure the impact of DG on transmission network expansion, it is important to determine what portion of the overall transmission expansion investment should be allocated to DG units. A number of transmission cost allocation methods have been proposed in the literatures. Two methods, *postage-stamp rate* method and *contract path* method [Shahidehpour, 2002], have already been widely used in the power industry due to their simplicity. These methods do not consider actual power flows and allocate transmission costs based on assumed usage of the transmission network. In practice however, the usages assumed by these two methods usually have large differences from actual network usages. Several other methods based on power flow calculations, such as *power flow tracing* [Shahidehpour, 2002] method and *influence areas* [Reta, 2005] method, are therefore proposed. Moreover, the transmission cost may also be allocated based on the economic benefits of different generators [Reta, 2005]. In our study, we will employ the influence areas method to determine the transmission expansion cost that should be afforded by distributed generators.

III. THE TRANSMISSION EXPANSION SIMULATION MODEL

In this section, we introduce the proposed model for simulating the transmission investment behaviors in a regional electricity market. The assumptions and the mathematical formulation of the model are firstly discussed. Since reliability is a main constraint of transmission expansion, we then discuss a probabilistic method for reliability assessment. We also introduce two security assessment methods for formulating security constraints in the model. Finally the influence areas method is introduced to allocate the transmission investments.

A. The Transmission Network Expansion Model

The model employed in this paper is based on AC optimal power flow (OPF) calculation. Power flow calculation is the most common power network analysis tool. Given the network topology, network devices parameters (e.g. line resistances and reactances), generatorsô information (e.g. capacities and costs) and projected system load levels, the OPF calculation can provide the voltage profiles of all nodes in the network, the power flows of all transmission lines, and the power outputs of all generators. In other words, OPF calculation determines how generators and the transmission network should be operated subject to the physical constraints of the network.

The following assumptions are made before we present the proposed model:

1. The transmission network expansion is conducted sorely by the transmission network operator.

This assumption is valid for any of the regional electricity markets in Australia, since currently in Australia private investors can only invest in the transmission lines between two regional transmission networks.

2. The market operator determines the generation schedules by minimizing the overall system generation cost. This assumption is identical to the policy of the Australian national electricity market (NEM).
3. All generators bid into the market at their short-run marginal costs.
4. The mandatory renewable energy target (MRET) and the renewable energy certificate (REC) market introduced in Australia provides policy incentives that are strong enough for the large-scale deployment of wind and solar power. In other words, we assume that the costs of wind and solar PV are no longer the barriers of their penetration.

Based on the above assumptions, the proposed transmission expansion model can be given as follows.

The first optimization objective is to minimize the total expansion investment:

$$\text{Minimize } O_{invest} = C^T \eta \tag{1}$$

where C is vector of the construction costs of all added transmission lines; η_{ij} is a integer indicating whether a new transmission line will be added in transmission route $i-j$.

The second optimization objective is to minimize the overall generation cost:

$$\text{Minimize } O_{gen} = \sum_{i\in G} f_i(P_{G,i}) \tag{2}$$

where G is the set of all generators in the system; $P_{G,i}$ is the scheduled real power output of generator i; $f_i(\bullet)$ represents the generation cost of generator i.

The following two constraints set up the relation between the injected power, the voltages and network parameters:

$$\text{Subject to} \quad P_{G,i} - P_{D,i} = \sum_{n=1}^{N} |Y_{in}V_iV_n| \cos(\theta_{in} + \delta_n - \delta_i) \tag{3}$$

$$Q_{G,i} - Q_{D,i} = \sum_{n=1}^{N} |Y_{in}V_iV_n| \sin(\theta_{in} + \delta_n - \delta_i) \tag{4}$$

Here $P_{G,i}, P_{D,i}$ are the real power output and demand of node i; $Q_{G,i}, Q_{D,i}$ are the reactive power output and demand of node i; $P_{G,i} - P_{D,i}$ and $Q_{G,i} - Q_{D,i}$ represent the real and reactive power injected into node i. Y_{in} is the element of the admittance matrix Y, which can be easily calculated from transmission line impedances after the network expansion as discussed in [Saadat, 2002]. θ_{in} is the angle of Y_{in} and can be given as $\theta_{in} = \arctan(\mathrm{Im}(Y_{in}) / \mathrm{Re}(Y_{in}))$. V_i is the complex voltage at node i, and δ_i is the angle of V_i ($\delta_i = \arctan(\mathrm{Im}(V_i) / \mathrm{Re}(V_i))$).

In constraints (5) ï (8), the limits of line flows, node voltages, generatorsô active power outputs and reactive power outputs are specified:

$$S_{ij} \le S_{ij}^{\max} \tag{5}$$

$$V_i^{\min} \le V_i \le V_i^{\max} \tag{6}$$

$$P_{G,i}^{\min} \le P_{G,i} \le P_{G,i}^{\max} \tag{7}$$

$$Q_{G,i}^{\min} \le Q_{G,i} \le Q_{G,i}^{\max} \tag{8}$$

where S_{ij} represents the apparent power flowing through line $i-j$, which can be calculated as $S_{ij} = \sqrt{P_{ij}^2 + Q_{ij}^2}$. Objective (2) and constraints (3)-(8) together formulate the standard OPF equations.

As mentioned above, enhancing the system reliability is the basic objective of network expansion. In practice, the transmission network operator will ensure that a minimum reliability level is reached after the network expansion:

$$EUE \le EUE_{\max} \tag{9}$$

where EUE denotes expected unserved energy, a widely-used reliability index.

Besides reliability, the system security is another important issue to consider in transmission expansion. In our model, we considered two security indices, the *voltage stability index* (VSI) and *transient stability margin* (TSM) in our models:

$$VSI \ge VSI_{\min} \tag{10}$$

$$TSM \ge TSM_{\min} \tag{11}$$

We will briefly discuss how to calculate EUE, VSI and TSM in the following sections.

In summary, the solution to model (1)-(11) gives the optimal transmission network expansion plan. In this study, we will divide the market simulation into *N* stages and assume that the transmission network operator will solve model (1)-(11) at each stage and implement the optimal expansion plan.

In practice, the system reliability can only be maintained by simultaneously expanding the transmission network and investing in new generation capacities. Therefore, generation investments will also be simulated in this study. Since we are interested in the impacts of large-scale penetration of DG, we assume that strong policy incentives exist in the market so that DG units will be investment priorities. Two scenarios are assumed in which DG will reach 20% and 40% penetration levels at the end of the simulation. If the added DG capacity is not enough for satisfying the minimum reliability requirement, the insufficient generation capacity will be met by building traditional coal-fire plants. The new coal fire plants will be built in the nodes with higher nodal prices. The nodal prices can be obtained from the OPF calculation.

Summarizing our discussion, the main procedure of the simulation is depicted in Fig. 1.

B. Reliability Assessment

Power system reliability can be seen as the degree of assurance in providing customers with continuous service of satisfactory quality. In this study, the widely used *expected unserved energy* (EUE) [AEMC, 2008] is employed as the index of reliability. The EUE is defined as the expected amount of energy that is not supplied due to the inadequate generation and transmission capacity. Different markets have different standards of reliability. In Australia NEM, the EUE should be limited within 0.002% of the overall energy traded in the market [AEMC, 2008].

The EUE can be calculated with OPF and Monte Carlo simulation. Before calculating the EUE, probability distributions should be firstly assumed to model load levels and the availabilities of all generators in the market. Load levels are usually assumed to follow normal distributions. The maximum outputs of wind turbine and solar PV are determined by the wind speed and solar irradiation, which can be modeled respectively with Weibull [Celik, 2003] and normal distributions [Kaplanis, 2007]. In each iteration of Monte Carlo simulation, load levels and the maximum outputs of generators are randomly generated. OPF is then calculated to determine the generation schedule. If all loads can be met, the unserved energy is zero. After N iterations of Monte Carlo simulation are finished, the EUE can be calculated as the average unserved energy of all N iterations.

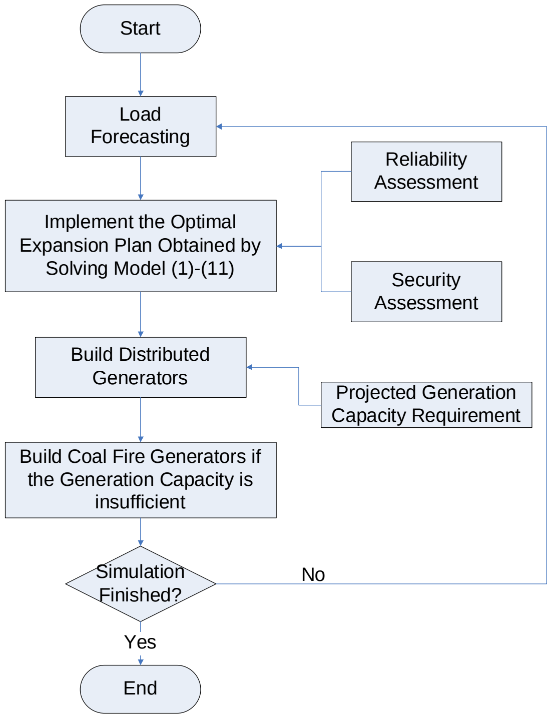

Figure 1 Procedure of the Transmission Network Expansion Simulation

C. *Security Assessment*

Power system security is its ability to withstand certain level of disturbances without losing stability. Losing stability can potentially cause blackouts and consequently incur severe economic and social damages. In this study, two indices, voltage stability index and transient stability margin, are employed to measure the system security.

Voltage stability is the ability of the power system to maintain the voltage levels subject to disturbances. Around the world, a number of large blackouts have been proven to be caused by voltage collapse [Lof, 1992]. A convenient method for voltage stability assessment is by employing *singular* *value decomposition* (SVD) [Lof, 1992]. For a power system with *n* nodes, denote $\bar{J}$ as the power flow Jacobian matrix [Lof, 1992], which contains the first derivatives of the real power and reactive power of all nodes in the system with respect to voltage magnitudes $\vec{V}$ and angles $\vec{\theta}$:

$$\bar{J} = [\begin{matrix} \partial\vec{P}/\partial\vec{\theta}, & \partial\vec{P}/\partial\vec{V} \\ \partial\vec{Q}/\partial\vec{\theta}, & \partial\vec{Q}/\partial\vec{V} \end{matrix}] = [\begin{matrix} \frac{\partial P_1}{\partial\theta_1},\dots,\frac{\partial P_n}{\partial\theta_n}, & \frac{\partial P_1}{\partial V_1},\dots,\frac{\partial P_n}{\partial V_n} \\ \frac{\partial Q_1}{\partial\theta_1},\dots,\frac{\partial Q_n}{\partial\theta_n} & \frac{\partial Q_1}{\partial V_1},\dots,\frac{\partial Q_n}{\partial V_n} \end{matrix}] \tag{12}$$

The smallest singular value of a matrix is a measure of distance between this matrix and the set of all rank-deficient matrices [Lof, 1992], the smallest singular value of $\bar{J}$ therefore can be seen as the distance to the voltage stability limit. Perform singular value decomposition of $\bar{J}$ we have:

$$\bar{J} = \bar{U} \times \bar{\Sigma} \times \bar{V}^T = \sum_{i=1}^{n} \sigma_i \vec{u}_i \vec{v}_i^T \tag{13}$$

where $\bar{U}, \bar{V}$ are two orthogonal matrices; $\vec{u}_i, \vec{v}_i$ are the columns of $\bar{U}, \bar{V}$. $\bar{\Sigma}$ is a diagonal matrix with

$$\bar{\Sigma} = [\begin{matrix} \sigma_1 & 0\dots & 0 \\ \vdots & \ddots & \vdots \\ 0 & 0\dots & \sigma_n \end{matrix}] \tag{14}$$

where $\sigma_1 \dots \sigma_n$ are the singular values. The smallest σ_i will be selected as the voltage stability index (VSI).

Another security index is the transient stability margin (TSM). Transient stability is the ability of all generators in the system to maintain Synchronization subject to disturbances. The transient stability margin gives an indicator of the distance to the transient stability limit. In our study, the widely used *extended equal area criterion* (EEAC) [Xue, 1989] method is employed to obtain TSM. EEAC firstly divides all the generators into two groups based on their characteristics. Each group is then aggregated to form an equivalent generator. The accelerating and decelerating energy of the system are then calculated to determine whether the two equivalent generators will lose synchronization and obtain TSM. The EEAC method is well-known for its superior computational efficiency and therefore has been widely applied in the power industry.

D. Transmission Expansion Cost Allocation

We employ the *areas of influence* method [Reta, 2005] to allocate the transmission expansion cost. The method is based on power flow calculation as well. It can be employed to determine the contribution of each market participant to the overall expansion cost. The method allocates the transmission cost based on marginal use of the network. The power flow will be firstly calculated for a typical system load setting as the base load flow case. A single generator will then be added into each bus successively. The area of influence of a specific node is defined as the transmission lines in which the power flows increase compared with the base case.

Based on power flow increases in transmission lines, it is possible to calculate a participation factor FPN of each generator for using a line

$$FPN_{ik} = \frac{P_{G,i} \dfrac{\partial P_k}{\partial P_{G,i}}}{\sum_{j=1}^{J} P_{G,j} \dfrac{\partial P_j}{\partial P_{G,j}}} \quad , \text{ if } \frac{\partial P_k}{\partial P_{G,i}} > 0 \tag{7}$$

$$FPN_{ik} = 0 \, , \text{ if } \frac{\partial P_k}{\partial P_{G,i}} \leq 0 \tag{8}$$

J is the number of system nodes, whose areas of influence include transmission line k. Areas of influence could be also computed by means of distribution factors, which are computed based on power flow equations. Finally, transmission expansion costs are calculated proportionally to participation factors.

IV. CASE STUDY RESULTS

A. *Case Study Setting*

The proposed simulation model is applied in the Queensland market, which is one of the six regions of the Australia national electricity market (NEM). In our study, the Queensland system is divided into 11 regions. The one line diagram of the Queensland network before simulation is given in Fig. 2. The overview of the Queensland system information before simulation is provided in Table I.

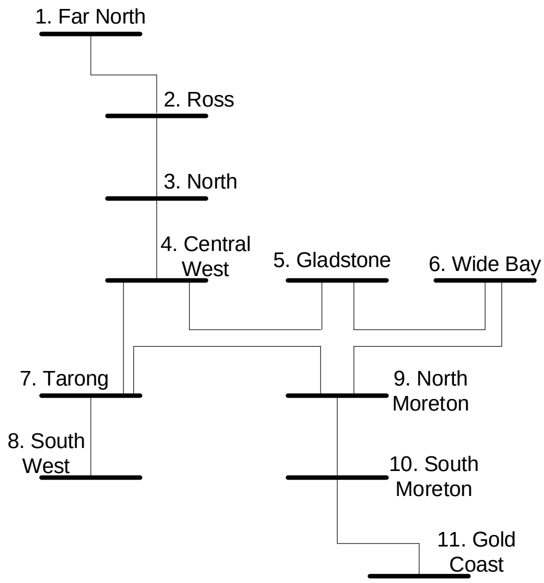

Figure 2 One Line Diagram of the Queensland Network

TABLE I QUEENSLAND SYSTEM INFORMATION

Nodes	11
Generators	53
Overall Load Level (MW)	6861.6
Overall Generation Capacity (MW)	9248
Overall Transmission Capacity (MVA)	25600

In our study, 6 different scenarios are created from the combination of two factors: DG technologies and maximum DG penetration levels. The overview of the 6 scenarios are given in Table II. The 20% penetration level is identical to the mandatory renewable energy target (MRET) of Australia government, while the 40% penetration level indicates a more aggressive market expansion of DG. In each scenario, the transmission expansion behaviors from 2010 to 2019 will be simulated. We assume that the penetration level of DG increases at a constant speed and reaches the maximum level at 2019.

TABLE II 6 SIMULATION SCENARIOS

Scenarios	**DG Technology**	**Maximum DG Penetration Level**
Base Case	No DG installed	0%
1	Wind turbine with simple induction generator (SIG)	20%
2	Wind turbine with SIG	40%
3	Wind turbine with doubly fed induction generator (DFIG)	40%
4	Solar PV Panel	20%
5	Solar PV Panel	40%

The projected load levels are assumed to grow at a constant rate of 3.6%/year, which is identical to the medium growth scenario in the report of Australian Energy Market Operator (AEMO) [AEMO, 2009]. AEMO also provides the required generation capacities for ensuring the system reliability objective (0.002%) from 2010 to 2019. In the base case scenario, the required generation capacity will be met only by coal fire plants. In the other 5 scenarios, generation capacity will be met by investing firstly in DG units, then in coal fire plants.

We assume that all new transmission lines will have a nominal voltage of 275 KV and a capacity of 250 MVA. The construction cost is assumed to be 45-50 M$/100km.

B. Wind Power Scenarios

The simulation results of the base case and three wind power scenarios are firstly given in this section. In the simulations, we assume that wind turbines can only be installed in Far North and Ross areas (nodes 1 & 2). This is because in Queensland, only the North-east coast line area has high wind power potential [Outhred, 2006]. The simulated transmission expansion investments and the EUEs for the base case scenario are firstly plotted in Fig. 3. As observed, the transmission investments are relatively small in the first three years, largely due to the sufficient transmission capacity at the beginning of the simulation. From Fig. 3 we can also observe that, since the reliability is a constraint rather than an objective in our model, the EUE generally is increasing.

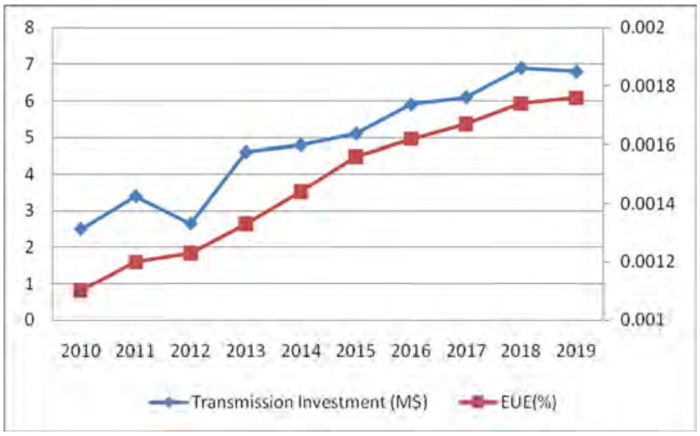

Figure 3 Transmission Investments of Base Case Scenario

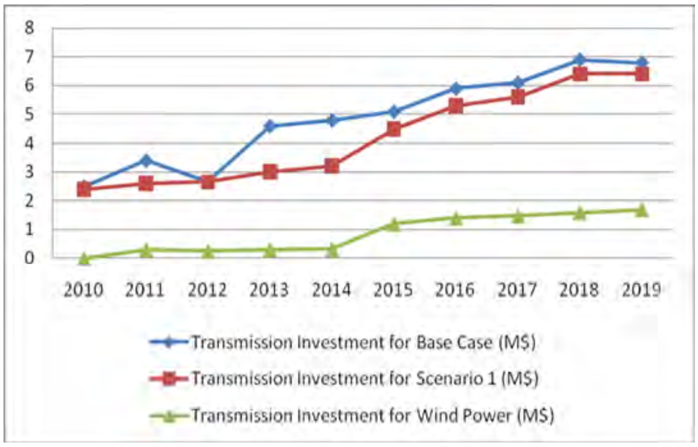

Figure 4 Transmission Investments of Scenario 1 (20% Wind Turbine with SIG)

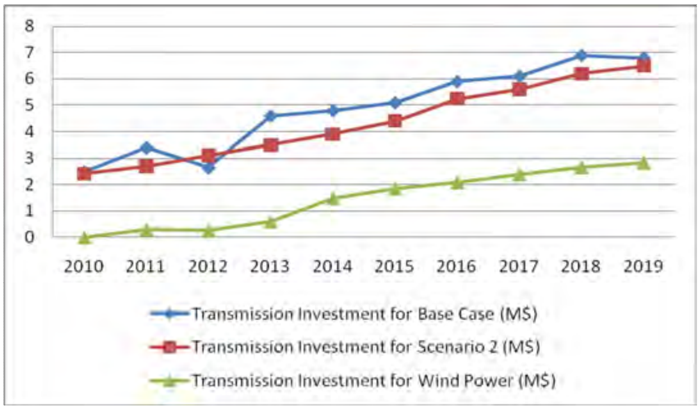

Figure 5 Transmission Investments of Scenario 2 (40% Wind Turbine with SIG)

The simulation results of scenario 1 are illustrated in Fig. 4. As observed, wind turbines do show a strong effect of transmission investment deferral in 2013 and 2014, because in the beginning stage of wind power penetration, it firstly satisfies local demands and thus reduces transmission congestions in North Queensland. After 2014 however, the wind power capacity has exceeded local demand and starts to be traded to other areas in the market. We therefore can observe that the transmission investments caused by wind power rise significantly from 2015. Moreover, the overall transmission investments from 2015 to 2019 are still smaller than the base case, but the reduced investments are much smaller compared with 2013-14. This is largely because the wind turbine has a very small short-run marginal cost. Therefore all wind turbines can be dispatched and are selling power to South Queensland, which are highly populated areas with high load levels. This trend significantly changes original power flow patterns, causes congestions between North and South areas, and triggers transmission investments.

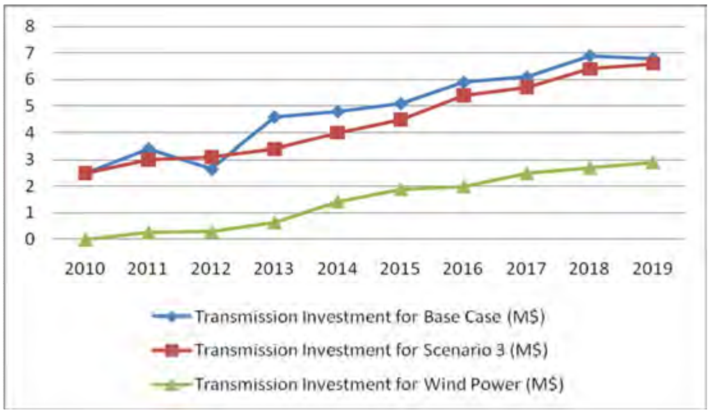

Figure 6 Transmission Investments of Scenario 3 (40% Wind Turbine with DFIG)

For scenarios 2 and 3, the transmission investment deferral effects are even smaller. As seen in Figs. 5 and 6, the investments caused by wind power start to increase in 2013. This is because in scenarios 2 and 3, wind power increases at a higher speed and exceeds the local demands of Far North and Ross in 2012, two years earlier than scenario 1. From the three wind power scenarios it can be observed that, whether DG can reduce transmission investments are largely determined by its location and the network topology. Placing DG units in inappropriate areas will significantly weaken the deferral effect.

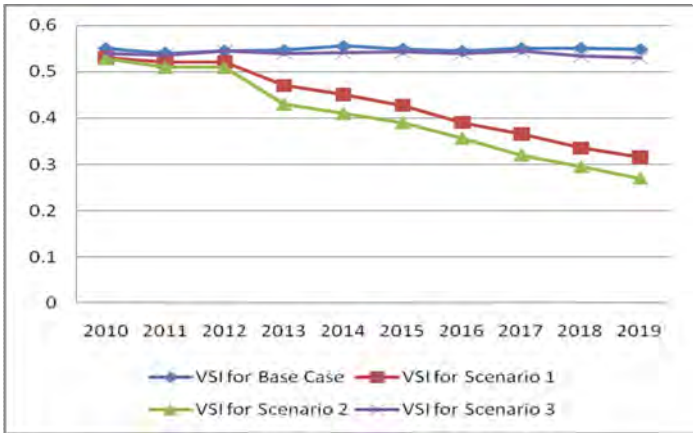

Figure 7 TSI for Wind Power Scenarios

The TSIs of three wind power scenarios are also plotted in Fig. 7. As observed, in scenarios 1 and 2, the penetration of wind power significantly worsens the voltage stability compared with the base case. This is because the wind turbines equipped with SIG cannot generate reactive power. The reactive power is usually drawn from local sources because the line loss of reactive power transmission is much greater than real power. Traditionally coal fire plants are main reactive power sources. In scenarios 1 and 2 however, there are insufficient reactive power capacities in Far North and Ross areas since only wind turbines are added into these areas. On the other hand, in scenario 3 the voltage stability remains at a reasonable level, since the wind turbines with DFIG can supply reactive power if necessary. To maintain voltage stability, voltage support facilities, such as capacitor banks, should be installed in the areas with high wind capacities. In practice, transmission network operator is responsible for investing in voltage support facilities; the cost of voltage support is also considered as a part of transmission investment. Therefore, the wind turbine with DFIG is a better DG option since it can reduce the voltage support cost.

C. Solar PV Scenario

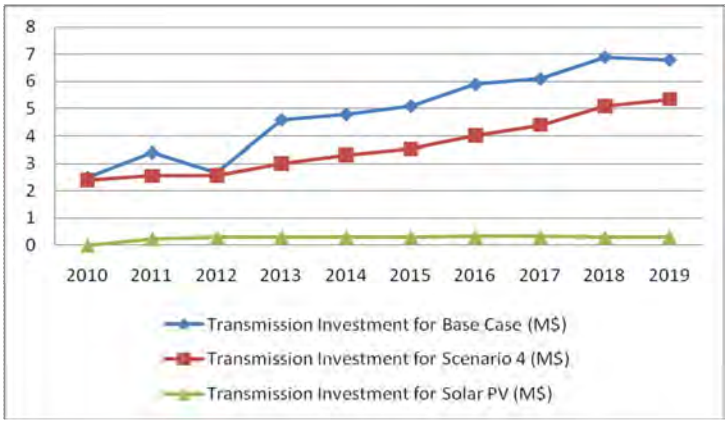

Figure 8 Transmission Investments of Scenario 4 (20% Solar PV)

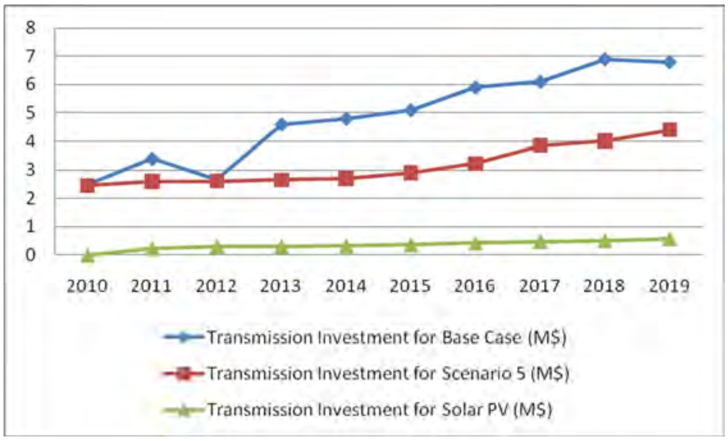

Figure 9 Transmission Investments of Scenario 5 (40% Solar PV)

In scenarios 4 and 5, we assume that solar PVs are evenly deployed in all 11 areas of the Queensland market. The transmission investments of two solar PV scenarios are illustrated in Figs. 8 and 9. As observed, in both two scenarios, solar PV shows strong effect of reducing transmission investments. Moreover, the investment for transferring solar power in scenario 4 is almost negligible. In scenario 5, the transmission investment for solar PV slightly increases, but is still small compared with the overall transmission investments. The reason behind these observations is, solar PVs spread evenly over the market, most of the solar power is therefore consumed by local demand. This mitigates network congestion and consequently reduces transmission investments. Compared with scenarios 1-3, we again confirm that the location of DG is an important factor to determine its impacts on transmission expansion.

The voltage stability index (VSI) of scenarios 4 and 5 are also plotted in Fig. 10. Solar PV panels will also worsen the voltage stability since most solar PV panels are operated at a power factor of one. They therefore cannot act as reactive power sources. At the beginning stages (2010-2013), VSI drops slowly, mainly because solar PVs are distributed evenly in all nodes, in which reactive power capacities (coal fire plants) are still sufficient. From 2014 however, the voltage stability has also worsened. Compared with scenarios 1 and 2, generally speaking the negative effect of solar PV panels on voltage is smaller than wind turbines with SIG, since in scenarios 1 and 2, wind turbines are all placed in Far North and Ross, which do not have sufficient reactive power capacities. However, local voltage support is still necessary for solar PV, by building either capacitor banks or traditional fossil fuel generators.

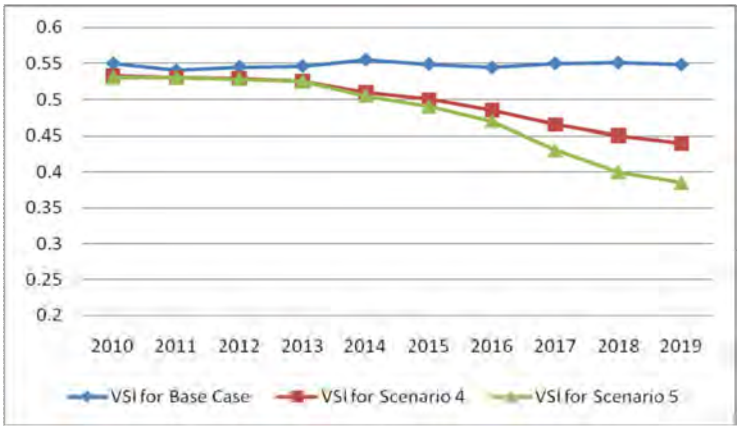

Figure 10 VSI for Solar PV Scenarios

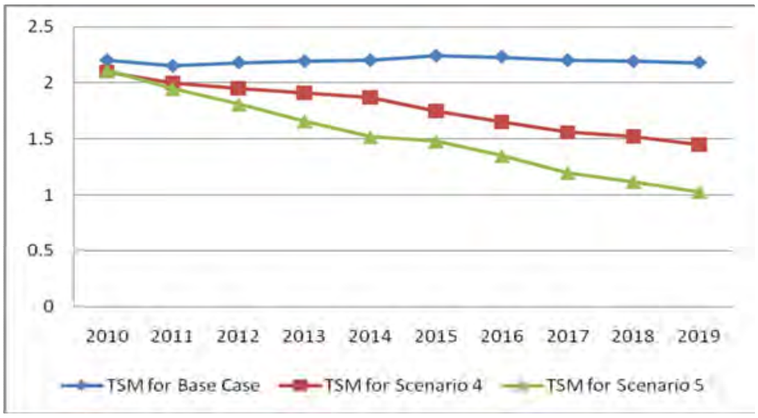

Figure 11 TSM for Scenario 5

The transient stability margin (TSM) for scenarios 4 and 5 is also depicted in Fig. 11. As is shown, the 20% penetration of solar PV already has a clear negative effect on the transient stability. Moreover, after solar PV achieves a 40% penetration level, the TSM has dropped nearly below 1, which indicates that the transient stability of the system has reached a dangerous level. In other words, from the viewpoint of system security, a 40% penetration of solar PV may not be feasible. The transient security therefore has also constrained the effect of solar PV on reducing transmission investments.

Summarizing the discussions above, we have following observations:

1. In general, both solar PV and wind power can defer transmission investments;
2. Whether the deferral effect is significant is determined by a number of complex factors, such as the locations of DG units, network topology and original power flow patterns;
3. The deployment and the correspondingly investment deferral effect of DG are also limited by technical constraints. For example, insufficient reactive power capacity will limit the deployment of solar PV and wind turbine with SIG. Transient stability will limit the deployment of solar PV.

V. CONCLUSION

In this paper, we aim at conducting quantitative analysis on what factors determine whether DG can significantly reduce transmission investments. We implement a transmission expansion simulation model, which is formulated as a multi-objective optimization problem with AC OPF and system security constraints. The model is then applied on the Queensland electricity market in Australia to study the impacts of two DG technologies, wind turbine and solar PV panel.

The simulation results indicate that, although DG generally can defer transmission investments, it is inappropriate to give a general conclusion about how strong this effect can be. In practice, the locations of DG units, the network topology, and the original power flow patterns all have significant impacts on DGôs investment deferral effect. In the Queensland market, solar PV exhibits a stronger effect of deferring transmission investments compared with wind power, since it can be deployed evenly in all areas of Queensland, while wind power can only be concentrated in North-east areas. Moreover, our simulation results also show that, the investment deferral effects of DG are largely limited by technical constraints, such as voltage and transient stability. It is therefore important to carefully consider these constraints when evaluating the actual benefits of DG.

VI. References

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