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Transmission Planning Considerations for DERs with Reverse Power Flow

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SUMMARY

Bulk electric system reliability is highly dependent on the balance of transmission line loading, system voltages and frequency, and overall system response during planned outage and fault conditions. Each of these factors are essential to bulk electric system reliability but are not typically evaluated in today's transmission planning processes with respect to DERs. Under reverse power flow conditions, high penetration aggregate DERs may require a similar analysis to the studies performed for generation interconnection requests. To understand and mitigate impacts caused by DERs, a reverse power flow analysis will be needed for future transmission planning considerations with DERs.

Whether it be through independent reliability assessments, coordinated dispatch approvals between transmission to distribution systems, or high-level mapping of DERs to transmission buses, ISOs are taking the essential first steps in integrating DERs into their transmission planning practices. Reverse power flow analysis will benefit from the results of these findings. Future studies will require detailed modelling, study procedures, and criterion to analyse impacts from DERs, similar to the procedures established for GI studies.

KEYWORDS

Reverse Power Flow, Distributed Energy Resources (DER), Transmission Planning, Generation Interconnection

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INTRODUCTION

Distributed energy resources (DERs) are becoming increasingly recognized as a key contributor in the United States electric power system. DERs are distinguished from traditional generation sources because they are connected on the distribution system and are not typically included in definitions or standard practices for the operation of the bulk electric system (BES). When connected near or directly at the load site, DERs can also be classified as end-use generation as the energy produced is used by specific on-site commercial or residential loads, or behind-the-meter generation (BTMG) when connected behind the utility's net metering point [1]. Renewable DERs have shown growth in recent years, both in utility-scale and residential locations. The Energy Information Administration (EIA) 2018 report indicated the capacity of end-use renewable generators makes up about 3% of the total generation capacity of the United States power sector. By 2050, the EIA projects this capacity will grow to more than 195 GW, contributing over 12% of the total generation capacity of the grid [1].

The purpose for end-use generation is to first serve the intended load before using the grid for its' remaining power supply. The owner of the DER or BTMG may also choose to sell any excess power back to the grid to support other distribution load demands when available. This condition can cause a "reverse power flow" on the system, where the direction of power is directed toward higher-level voltages which is contradictory to the traditional flow of the grid (high-voltage source to low-voltage load). If unconsumed by the surrounding distribution loads, the aggregate output of a certain area of DERs may carry over to the transmission system. High penetration of DERs can alter the balance of transmission line loading, bus voltages and frequencies during normal conditions, and affect the overall system response during planned outage and fault conditions. Each of these factors are essential to bulk electric system reliability but are not typically evaluated in today's transmission planning processes with respect to DERs. Although end-use generation is considered relatively insignificant at its present capacity, the increase in high penetration DERs will create a need for the impacts of reverse power flow to be uniformly addressed and studied at the transmission level in greater detail.

TRANSMISSION PLANNING CONSIDERATIONS FOR DERs

The reliability impacts of DERs have been integrated into distribution performance standards as the effects are more easily understood, monitored, and mitigated when studied at the same level. Standard IEEE-1547 outlines the technical criteria for and performance requirements for interconnection of DERs but does not give any recommendations for maximum capacity or planning techniques when considering the impacts of DERs that may be seen on the transmission system [2].

Generation Interconnection Studies

For transmission resources, any generation that intends to connect to the BES system must be submitted to the respective transmission system owner through a generation interconnection (GI) request. This allows all generation to be studied in detail for necessary network upgrades and potential reliability impacts should the generation be connected to the system. A steady state study determines any facilities that have thermal overloads and low or high voltages above a certain threshold as defined by the owner of the asset or regulatory standards. If the generation causes an impact, the planner must report the affected facility and recommend mitigation efforts to prevent system failures (typically involving network upgrades). Short-circuit analysis determines the short-circuit power levels which dictate protective relay settings and equipment ratings. Dynamic (transient) stability observes the response of a system both during and after a fault, primarily through monitoring rotor angles, voltage and frequency of generators or buses throughout simulation.

Reverse power flow from DERs changes the direction and magnitude of flow within the transmission system, which, depending on the location of the additional flow, can have significant reliability impacts. This presents a unique challenge for evaluating transmission system reliability: at higher levels of DER penetration, the reverse power flow condition created by aggregate DERs may cause similar impacts to transmission system reliability as a new generator. DERs may increase or decrease the number of impacted facilities in steady state and may increase the overall short-circuit current. Under fault conditions, reverse power flow may affect the system's ability to stabilize should the variable nature of renewable DERs lead to asynchronous conditions or voltage levels that cause surrounding systems to trip. DERs are not required to enter through a transmission GI request, as they are connected to the distribution system and are not controlled or operated by a transmission system entity. However, a similar business practice may be needed for evaluating high penetration aggregate DERs at the transmission level to perform similar studies and identify the potential impacts.

Modelling DERs in Planning GI Studies

To address how DERs are to be evaluated for similar impacts as in GI studies, it is helpful to understand how distribution resources are typically modelled in transmission system analysis. In the base case, the entire distribution system is not modelled as the system would be too large to perform a reasonable study for the intended area of interconnection. Instead, distribution loads and resources are typically represented as an equivalent load seen at by a transmission system bus, where DERs are treated as negative loads [3]. Simplifying this model allows for shorter simulation time and is acceptable if assuming static loads, constant output of DERs, and low levels of DER penetration. Under reverse power flow conditions, the net load seen on the transmission system would be negative.

If DERs are not modelled as generators at the transmission bus, the variability in output as well as the DER characteristics can cause inaccuracies when studying reverse power flow impacts on the transmission system. This distinction in methodology is vital to transmission system analysis as simulating a load is very different than simulating a generator, especially in short-circuit and dynamic stability studies. Dynamic stability simulations require dynamic data that links the generator's properties, such as speed and angle (for synchronous generators), terminal voltage, and damping parameters to the generator. Data is also required for any protective device settings that limit the generator's response and active generator tripping. Renewable generators can require even more data to include inverter characteristics in simulations. Representing highly variable, diverse generators in such a simplified manner is not appropriate for reverse power flow analysis.

The issue of how to best represent DERs in transmission system studies is already recognized within the industry. Power system software allows for a DER component as part of the aggregate load at a distribution bus for a more realistic simulation. In September 2019, NERC released a Reliability Guideline[1] recognizing the DER_A model as an acceptable and well-tested model for representing aggregate or standalone inverter based DERs for power flow and stability simulations [4]. The model defines two groups of DERs: U-DERs, which are "utility-scale" DERs either directly or closely connected to distribution system buses (non-load serving), and smaller-scale R-DERs which are commonly used to offset residential loads. NERC suggests R-DERs should be accounted for in dynamic simulations as an "explicit DER component" if the gross aggregate nameplate rating exceeds the R-DER distribution system threshold [4]. If the threshold is set at 0 MVA, all forms of DERs would be separately accounted for apart from the total netted load. The DER_A model offers a way to integrate DERs into transmission planning studies for future analysis of reverse power flow impacts. In the future, base case models may need to begin incorporating this model into their base cases for accurate system analysis.

[1] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf#search=der%5Fa

DERs WITHIN THE TRANSMISSION INDUSTRY

As discussed in the above sections, there is no need to develop a standard methodology for evaluating DERs with reverse power flow from distribution to transmission systems with the present levels of renewable penetration. Instead, most transmission entities are assessing the known or potential impacts of DERs on their systems via independent working groups to address the how DERs will affect their current business practices. From a transmission planning perspective, it is important to understand how the transmission industry is focusing on DER impacts to position for future studies involving reverse power flow. The following section overviews recent assessments from DER study groups within three United States Independent Service Operators (ISOs), MISO, CAISO and ERCOT. The goal is to identify takeaways from these ISOs for future transmission planning modelling and analysis that can be referenced for reverse power flow analysis.

DER Concerns at the ISO Level

MISO releases Renewable Integration Impact Assessments (RIIAs) which aim to identify and mitigate system "inflection points" where the existing infrastructure and operations may require modification for a given penetration level of renewable generation [5]. It is in these assessments that the entire transmission system is monitored and analysed with high penetration DERs, as part of MISO's total renewable portfolio, using the same power flow base cases that are used for GI studies. The latest assessment models R-DERs as constant-current negative loads at the transmission bus, separate from the distribution loads and unable to provide reactive power support [5]. Both steady state and dynamic stability analysis is performed to address the impacts incurred by high penetration renewables on transmission facilities and system stability and frequency response. This is reasonable for MISO's study purpose, as DER penetration level is a relatively small portion of their total renewable portfolio. As DER penetration levels increase, using a more detailed model for DERs may be required for dynamic studies.
Aside from the RIIAs, MISO engages stakeholders in "issue tracking" and has held several workshops over DERs in 2019. However, the focus is primarily on the demand response aspects of DER integration and has not addressed reverse power flow impacts associated with high penetration DERs at this time.

Although ERCOT's Distributed Generation and Distributed Resource Energy and Ancillaries Market task forces are both currently inactive according to the ISO's website, ERCOT did publish a DER reliability impact assessment of their system in 2017. Several impacts of high penetration DERs were discussed including potential cascading under fault conditions or as a result of large clusters of DERs disconnecting at a single time [6]. To mitigate these and other impacts, coordination for mapping DERs to their transmission loads between ERCOT and the transmission and distribution service providers with annual readjustment was recommended. ERCOT recently posted a short summary of DERs in ERCOT's system as a "trending topic," discussing the operating concerns and visibility strategies currently being explored, including DER mapping. In current business practices, it is now a requirement for any DER generator larger than 1 MW that participates with the wholesale market must register with the ISO. Units smaller than 1 MW are not required to register – this amounts to an estimated 530 MW in 2019 [7]. ERCOT's 2017 report also recommended incorporation of new contingencies for sudden loss of aggregate DERs to test for potential cascading in stability simulations [6]. Creation of contingencies related specifically to DERs will be a significant step in studying reverse power flow in future transmission planning efforts.

Likely due to the already high penetration of renewables in California, CAISO has developed a more standardized process for integrating DERs into their standard transmission planning procedures. As outlined in CAISO's 2018-2019 ISO Transmission Plan, distributed generation levels are evaluated each year via a two-step planning process. First, a deliverability study determines the transmission level capacity of aggregate DERs at a given bus for which no network upgrades are needed, and no existing or queued transmission sources are adversely impacted. The model uses base case resource portfolios for DERs in previous planning cycles to set a minimum DER level of deliverability, and a maximum for which distribution utilities can use to communicate to the downstream utilities for approved generator dispatch for interconnection agreements [8]. This capacity is then communicated back to transmission planning as projected aggregate DER capacity for transmission system modelling; the projected capacity is used as an input in load models under the DG field [9].

Future Considerations in Transmission Planning

ISOs approaches for studying DERs vary from high level penetration studies, to localized impact studies. As DER penetration levels increase, impacts from DERs may become an equal factor in reliability concerns as transmission-level generators. ISOs may want to develop procedures for studying reverse power flow at the transmission system for DER, similar business practices for GI studies. In GI studies, any necessary mitigations to the impacts seen from steady state or dynamic studies are reported to the responsible generator for network upgrade costs or other solutions such as adjustments for protection devices. A criterion for assigning the responsibility of costs or mitigations will also be needed for respective DER impacts, except these sources will be on the distribution level. In order to assign costs, a modelling technique or process will be needed to allocate costs to individual DERs within the aggregated group.

Studying DERs can also provide value for GI studies themselves. If it is found that a cluster of DERs causes a need for a network upgrade, a generator undergoing a GI study within the same area may have a shared impact. If the facility is upgraded due to the DERs already on the system, the generator requesting interconnection to the transmission system may require less network upgrade costs and continue through the queue as a result. Transmission system base case models may need to be updated with reverse power flow analysis results and high penetration aggregate DER points to incorporate this level of visibility and accuracy for future GI studies. This will be a continued effort that will require communication between distribution system providers, as well as neighbouring transmission utilities and system operators will be necessary if high penetration impacts in specific area will affect more than one power provider. ISOs or other transmission system entities may see a need for a specialized business practice manual addressing high penetration DERs as their systems become increasingly integrated and more complex.

CONCLUSION

New generation on the transmission system is evaluated for adverse impacts to system reliability. As DER penetration levels increase, impacts from DERs will need to be assessed, especially under reverse power flow conditions. Whether it be through independent reliability assessments, coordinated dispatch approvals between transmission to distribution systems, or high-level mapping of DERs to transmission buses, ISOs are taking the essential first steps in integrating DERs into their transmission planning practices. Reverse power flow analysis will benefit from the results of these findings. These studies will require detailed modelling, study procedures, and criterion to analyse impacts from DERs, similar to the procedures established for GI studies. These studies will provide visibility into impacts of DERs on the transmission system, which will be necessary for maintained system reliability in the future.

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