Renewable Energy Coalition

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Via Electronic Mail

Public Utility Commissioners of Oregon
Chair Megan Decker
Commissioner Letha Tawney
Commissioner Les Perkins

Re: UM 2111 December 4, 2024 Workshop Renewable Energy Coalition Comments

Dear Oregon Public Utility Commissioners and Staff,

Thank you for hosting the UM 2111 Interconnection Workshop on December 4, 2024. In response to the discussion during the workshop, this document compiles comments and ideas from the Renewable Energy Coalition (the "Coalition").

Much of the discussion during the workshop focused on the rationale for direct transfer tripping ("DTT") inverter-based generation (inverter distributed generation ("DG")) during grid contingency events for mitigating adverse system impacts and preserving reliability. The Coalition wholly supports efforts to ensure safe interconnections and preservation of reliability, and in no way should our comments be construed as otherwise. That said, in many instances the utilities are single-mindedly over-reliant on protection methods that assume DTT is the only technically available solution, or the only 100% safe solution. In reality, other protection methods can be implemented (and are being implemented!) to achieve a functionally identical result to address any adverse system impacts caused by the interconnection of a small generator facility. The question of whether DTT is a reasonable protection requirement depends on if the assumption that inverter-based generation can maintain an unintentional island is rational. The assumption is not accurate. From a technical standpoint it is not possible for inverter-based generation to maintain an unintentional island. Therefore, the utilities are unreasonably relying and imposing DTT on inverter-based interconnection customers. A review of some of the technical facts that surfaced at the December 4th Interconnection Workshop are summarized below:

1. **Review of the utilities' stated intention of DTT**

The utilities stated intention of DTT is to prevent an unintentional island forming during a grid event when the power source upstream of the inverter DG is disconnected from the circuit and to prevent the utility from reclosing onto an island in attempts to restore service. The safety assumption is that all unintentional islands create abnormal voltages that damage customer and utility equipment. However, the preconditions necessary for an unintentional island to occur must be considered. For an unintentional island to form the following must occur:

a) The real power on the circuit must be in balance (in reality there is no real power flow through a feeder breaker the instant it is opened)
b) The reactive power on the circuit must be in balance (in reality there is no reactive power flow through feeder breaker at the instant it is opened)
c) Breaker opened but no overcurrent fault
    a. E.g., Remote breaker opening, operator action
    b. Faults create abnormal voltages which inverters and supplemental utility-grade relays react to, disconnecting the inverter DG
d) A breaker trip caused by a fault will create abnormal voltages on the circuit which can be detected

<u>For an unintentional island to form, all of the above events need to occur simultaneously – the probability of this happening is extremely, extremely low – perhaps even impossible.</u> Furthermore, there is no known industry evidence that inverter-based generation can contribute to any of the requirements necessary to maintain an unintentional island.

Utilities claim the main reason they must use DTT is that they cannot rely on an inverter's inability to maintain an unintentional island, and therefore cannot rely on the inverters' IEEE 1547 requirement of tripping offline within 2 seconds of detecting an island (this has been a requirement of IEEE 1547 since 2003). Furthermore, utilities claim that an inverter's ability to react and detect an island is reduced during periods of backfeeding. This is based on the idea that at the moment of a grid event, it *might* be theoretically possible for the operating inverter DG to be balancing load. However, inverter-based generation, as requested by utilities, does not provide any reactive power, which is one of the features necessary to maintain an unintentional island as noted above. Therefore, it is technically impossible for an inverter DG to maintain an island, nor do they provide any "inertia" like rotating generators.

2. **Utilities say they need DTT because they need to ensure generation is tripped offline in less than 2 seconds as to not conflict with high-speed reclosing**

Another reason utilities claim they need DTT is to allow for superfast high-speed tripping to accommodate existing high-speed reclosing schemes, where the reclosing interval occurs in less than 0.3 seconds. The Coalition takes issue with this idea for a handful of reasons.

First, high speed reclosing is not standard across many utilities. Some utilities say it is used to limit customer impact by preventing longer duration flickers. However, in reality, the Coalition believes that reliability up-time is only marginally impacted by high-speed reclosing practices vs slower reclosing intervals.

Second, the Coalition notes that any perceived benefit to reliability from high-speed reclosing may be offset by the damage it can cause for load customers that have large industrial motors connected to the circuit.

Third, the use of hot line blocking reclosing schemes ("HLB") indicates utilities are willing to tolerate slower reclose intervals. A HLB scheme allows the reclosing to be delayed via a potential transformer sensing if there is any remaining voltage on the feeder after the feeder breaker opens, whether the voltage is caused by an inverter DG or by a large motor load. If any voltage is present after the upstream feeder breaker opens, then HLB will delay and prevent reclosing onto the persistent "hot line" – hence the name "hot line blocking". HLB schemes prove that utilities are willing to accept reclose intervals longer than the timing they select for high-speed reclosing.

Furthermore, at the December 4th workshop the utilities mentioned their wildfire mitigation practices delay or avoid reclosing altogether during fire advisory periods – fire advisory periods can last for months at a time. This suggests utilities find it acceptable to forego any perceived "benefits" of high-speed reclosing in many cases. If utilities are willing to tolerate slower reclose intervals from HLB schemes, then the Coalition does not believe it is reasonable for utilities to claim DTT is necessary to maintain high speed reclosing schemes.

3. **Utilities' existing practice of HLB schemes on feeders for some inverter DG interconnections proves utilities acknowledge and accept inverter tripping capabilities without DTT**

Current use of HLB schemes for some inverter DG interconnections when generation does not exceed daytime minimum load on the substation transformer provides tacit proof that utilities do not need to use DTT to prevent unintentional islands and that tripping capabilities of the inverters are acceptable.

Utilities like PGE will require HLB to be installed on the feeder breaker but not require DTT to the new inverter DG (see Sections 3.6.3.1 versus 3.6.4.4 of PGE's 2024 Distribution Interconnection Handbook) in certain circumstances. Specifically, DTT is not required for inverter DG interconnections where the incremental generation from the new inverter DG exceeds the daytime minimum load on the feeder but is less than the daytime minimum load on the substation transformer (i.e., backfeed up through the feeder but not through the substation transformer onto the higher voltage system). In this protection scenario HLB is used to prevent reclosing onto an island if an inverter DG were to remain energized. When the feeder breaker opens, then all downstream inverters will trip on sensing the load/generation imbalance. HLB is used to confirm all generators are offline before allowing the reclose attempt. This is because the HLB senses the line is dead and then allows the feeder breaker to reclose.

This existing scenario of a utility using HLB when a generator exceeds the daytime minimum load threshold on the feeder, but not the transformer, is a tacit utility acknowledgment and acceptance of an inverter's inherent anti-islanding capabilities. In the HLB scenario, the utility is willing to accept the anti-islanding capabilities of the inverters without any other extraneous form of tripping like DTT. It is also existing proof that HLB is a viable alternative to create and maintain the conditions necessary to avoid unintentional islanding and for inverters to trip on their own.

In addition, the HLB scheme when the inverter DG generation exceeds the daytime minimum load on the transformer can also be used to disconnect and prevent the inverter DG from being a source into a transmission-level fault. Some utilities normally trip feeder breakers when a transmission fault occurs. This prevents transient over-voltage from restoration of the transmission system from affecting all customers and prevents distributed generation from feeding a transmission fault.

4. Utilities claim that superfast tripping via DTT may also be necessary to prevent "damage"

Utilities claim that superfast tripping via DTT may also be necessary to prevent "damage". However, it is important to consider some technical facts in assessing whether this "damage" risk is reasonable. The typical method for quantifying fault energy is I^2t. If a feeder sees 3000A (typical for 12.5kV feeder) and clears a fault in 6-cycles, then the I^2t is 900,000A^2s (this assumes no reclosing and fast fuse-saving scheme – fuse-blowing clearing times are likely 0.5-1.0 seconds). A 2MWac inverter DG will generate 100A into a fault. If it takes the full 2-seconds to shut down and generates the full 2MW for the entire 2-seconds, then the I^2t is merely 20,000A^2s (this assumes a full 2-seconds is needed for the inverter DG to shut down whereas industry testing indicates actual shut-down times are under 1-second). This example illustrates that the energy fed into the fault by the inverter DG is <u>45-times less than what is fed into the fault by the utility!</u> Therefore, the Coalition does not think the utilities "damage" logic from persistent inverter DG generation is reasonable.

5. **Utility over-prescription of DTT prevents inverter DGs from complying with ride-through requirements of IEEE 1547-2018**

Lastly, the Coalition points out that utilities over-use and over-prescription of DTT prevents inverter DGs from performing their recommended ride-through functions as noted in recent IEEE standards. The Coalition feels this is worth examining as the utilities may be preventing inverter DGs from fully complying and providing all the intended grid benefits contemplated in the latest IEEE standards.

Conclusion:

The Coalition believes that what is at issue in this debate is whether an appropriate cost-benefit analysis is being considered when it comes to DTT. When interconnection customers are forced to pay for everything, then the cost to the utility is zero so the cost-benefit ratio is more advantageous to the utility. But where the probability for the risk is low, the cost for the benefit is extremely high. A uniform and unbiased consideration of the costs and perceived benefits of DTT protection schemes is needed to ensure interconnection customers only pay the reasonable costs for their interconnections. The considerations for the costs-benefit analyses should take into perspectives of the interconnection customer, the utility, utility load customers, society as a whole, and broad policy goals.

Submitted respectfully,

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