



UTILITY INTERCONNECTION FOR SMALL RENEWABLE ENERGY PROJECTS

RULES OF THUMB, REFERENCES AND RELEVANT CASE STUDIES

Interconnection of a distributed power resource to the utility grid is an aspect of project development that is new to many small-scale renewable project developers. To streamline and clarify the process across Oregon, the Oregon Public Utilities Commission (OPUC) adopted new rules in 2009 known as AR521 or OAR 860-082-0020 to 0060. These rules govern interconnection of Small Generators to the Investor-Owned Utilities (IOUs)¹ in Oregon. A small generator is defined as a facility for the production of electrical energy that has a nameplate capacity of 10 megawatts (MW) or less. A small generator facility does not include interconnection equipment, interconnection facilities or system upgrades.

Although AR 521 vastly improved the interconnection process, project developers and utilities sometimes interpret these rules differently, leading to misunderstandings and often delays in project construction. Issues that project developers commonly experience fall into three categories, each discussed in this document:

- 1** Variance in the timeline for interconnection compared to what is suggested in the rules.
- 2** Changes in the utility's interconnection cost estimates between each of the three study phases (Feasibility Study,

System Impact Study and Facilities Study) for projects as well as variance between the Facilities Study and the final cost of interconnection.

- 3** Difference between the project developer's and utility's interpretation of the Tier-qualifying criteria.² (For example, a developer may think a project is Tier 2, while the utility considers it Tier 4). Another common occurrence is variance between a utility's determination of a project that meets Tier 1 and Tier 2 screens and the project developer's interpretation of screens as presented in the rules.

As you'll learn when you read the rules of thumb presented in this document, there is no substitute for being well prepared and knowledgeable about the interconnection process and contacting your interconnecting utility early in the development cycle. Having a good understanding of the rules and procedures well before you submit an application for interconnection will help alleviate much of the confusion in what is a complex process. You'll be able to navigate the process with minimal surprises and better meet your construction timelines cost-effectively.

¹ Oregon IOUs: PacifiCorp, Portland General Electric, and Idaho Power Company.

² For definitions of Tiers 1 through 4, see "Interconnection Guidebook" at www.energytrust.org/library/reports/100908_Interconnection_Guidebook.pdf.



It also helps if you're able to identify upfront any characteristics of your project (location and/or generator-specific) that could lead to any of the following:

- Allow your project to benefit from a reduced timeline
- Cause your project to suffer a delayed timeline
- Result in large differences in cost estimates between study phases
- Bump your project up to the next Tier
- Cause a utility to require an extra study that may not be apparent from reading the procedures

The goal of this document is to help you identify where your project may fall outside the black-and-white interpretation of the rules and where there could be opportunities for you to reduce cost and time. Ultimately, the best advice for any project developer new to the interconnection process is to start early and work closely with your utility, providing utility staff with all the information they need in a timely manner.

The material here is based on past history with real projects. It supplements, but does not replace, guidance in Energy Trust's [Interconnection Guidebook for Developers of Small-Scale Renewable Energy Generation Systems](#). If you are not yet familiar with that guidebook, start there. The guidebook will help your project proceed more smoothly and will allow you to get the greatest benefit from this document.

There are four categories or Tiers available for an interconnection project. The respective process and rules are going to be determined by the requested interconnection Tier. Only inverter-based (generally solar photovoltaic) projects up to 25 kW may apply for Tier 1. Any resource type up to 2 MW may apply for a Tier 2. Any resource type up to 10 MW may apply for Tier 3; this Tier does not allow power export (sale). Any resource type up to 10 MW may apply for Tier 4, which does allow for power export (sale).

Timelines for interconnection

AR 521 rules specify appropriate timelines for each step of interconnection, from the application to the interconnection agreement. However, either party may delay the process, with proper notification, if there is an extenuating circumstance.

The AR 521-specified timelines are as follows (all business days):

- For Tier 2-4, the scoping meeting should occur within 10 days of the utility advising the interconnection application is complete enough for review. The scoping meeting gets all parties together to discuss timeline, the interconnection process and project-specific issues. The scoping meeting can be waived through bilateral agreement if it is believed to be unnecessary.
- For each level of system study:
 - five business days for the utility to supply the appropriate study agreement(s) to the customer, as they are found to be necessary, and five days to supply the interconnection agreement after an interconnection application has been approved.
 - 15 days for the customer to execute any required study agreement(s) and 15 days for the customer to return to the utility a signed interconnection agreement once received.
 - The utility must provide a timeline to complete each study and complete each study within the provided timeline. It typically takes three months or more for the utility to complete each study, although the Feasibility Study is generally completed sooner.

At the end of all required studies, the utility is allowed 15 days for application approval. Generally, an entire interconnection scoping and study process, which requires a Feasibility Study, System Impact Study and Facility Study, can take four to 10 months, sometimes up to 12 months.

TIMELINE CASE STUDY

Juniper Ridge Hydroelectric Plant

Developed by the Central Oregon Irrigation District (COID), Juniper Ridge is a 5 MW hydroelectric synchronous generator power plant in service in Deschutes County. Juniper Ridge is interconnected to PacifiCorp's Tumalo (Bend-Redmond) 69 kV line south of Deschutes Substation.

Like many generation projects, Juniper Ridge had to meet a strict timeline (12 months) for project financing and to qualify for the full range of financial incentives for this \$20 million project. As a result, the developer decided to waive the Feasibility Study and move directly to the System Impact Study.

The System Impact Study determined that there were no adverse effects on PacifiCorp's distribution system from interconnection of Juniper Ridge. The study stated that there would be no "transmission system overloading," and that "voltage steps due to switching" would be less than the

five percent maximum—all good indicators for a smooth interconnection process.

But the project did require significant work to move the generation from the project to the Point of Interconnection (POI) substation. Nearly 90 percent of the total interconnection costs estimated were for work needed on the "project side" of the meter, and the project had an estimated commissioning date of 18 months after the execution of the interconnection agreement. The 18-month estimate was determined by the utility based on its workload and project queue. The utility's staff and contractor pool was already scheduled to complete other projects prior to being able to do this work.

After COID communicated its timeline constraint to the utility, the utility allowed COID to take responsibility for subcontracting most of the POI substation upgrades, in order to accelerate the commissioning date. As a result, COID was able to manage 90 percent of the work and meet its 12-month timeline.

Rules of thumb impacting timelines

Suggestions for the scoping and study phase include:

- Use the scoping meeting to clarify timelines and utility requirements.
- Execute interconnection study agreements, deposits and correspondence promptly.
- Build additional time into the schedule for interconnection studies and agreement if possible, a minimum of 18-24 months.
- Execute procurement agreements and procure long-lead time materials early. Examples include breakers, metering current transformers (CTs, which are used to measure electric current levels to enable metering) and potential transformers (PTs, which step voltage down to a level meters can handle).
- Choose carefully before skipping a scoping meeting or studies.

Although atypical, the scoping meeting and any of the studies may be waived upon mutual agreement between the developer and the utility. This option saves time and cost, but can add risk. If the developer has done pre-feasibility research, there may be little risk, but if there is little insight into the possible interconnection outcome, then each study can give the confidence to continue investing time and money by proceeding. When skipping occurs, the most common scenario is to skip the Feasibility Study, the first in line, with the utility requiring the System Impact Study and the Facility Study.

For a Tier 4 project, the developer may choose to skip the Feasibility Study (if unnecessary). Rather than screens, Tier 4 projects involve a rigorous series of studies that are conducted to determine how the proposed project will impact the electrical system. The interconnection customer may elect to skip the Feasibility Study to reduce the interconnection timeline. The risk is missing out on a good estimate of system capacity and facility upgrade cost early in the process, which can impact project decisions down the road.

After the study or studies are completed, the interconnection agreement is signed. Next, the utility will identify the timeline for the project construction process. The timing of this work depends on availability (workload) of utility line crews. (Utility crews are required for distribution, transmission or substation upgrades, as well as equipment that the utility will own, maintain and be responsible for.) Rules of thumb for this stage include:

- Learn about current utility work plan schedules (months or years) by asking your utility about its queue and plan accordingly.
- Ask to take responsibility to subcontract crews for utility upgrades when applicable—you may succeed in negotiating an expedited timeline.



VARIANCE BETWEEN COST ESTIMATES APPEARING IN THE FEASIBILITY, SYSTEM IMPACT AND FACILITIES STUDIES

The Oregon Small Generator Interconnection Tier 4 process recommends up to three studies. Through this study process, estimates of technical requirements and associated costs of interconnection become increasingly more detailed and accurate.

Sometimes the initial estimate is accurate and further study confirms this. However, some developers have seen very high estimated costs shrink to manageable levels. Others have seen promising estimates balloon to cost-prohibitive amounts late in the process, after time and money have already been invested.

Overly conservative (high) estimates can unnecessarily halt promising projects, while estimates that start low can cause a project developer to spend resources on a project that is not financially viable.

Unfortunately cost estimates have no guarantee of accuracy. The rules do not set an allowed percentage variance. They only require that project owners pay the cost of safe interconnection. For a more accurate estimate, the developer may request a site visit be included with the set of studies. This will add additional cost to the study, but will produce a more accurate estimate.

Conditions that can affect cost

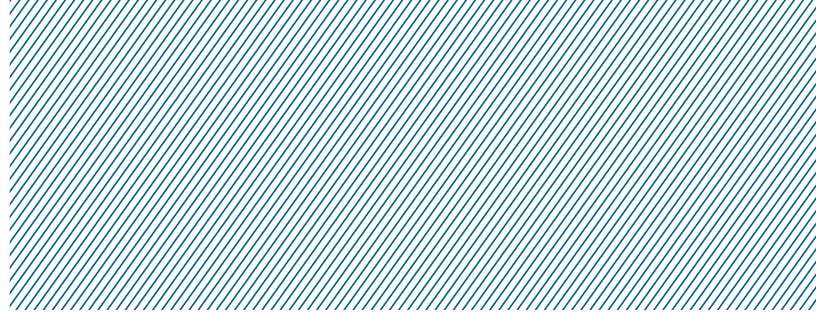
- Proximity to utility substation—a nearby substation could indicate a stronger local utility system that requires fewer upgrades.
- Road access—older distribution systems without road access could require roads before the utility can upgrade.
- Telecommunication—nearby utility fiber communication lines make a simple and fast communications connection.

Rules of thumb

- Focus on key, high cost items.
 - Can wireless (cellular) communication be used instead of fiber? There can be a preference on the part of the utility for fiber. However, if transfer trip is not required,

wireless is equally reliable, secure and fast, while also less expensive.

- Phasor Measurement Units (PMU) or other measurement equipment can benefit the system. However special high-cost measurement equipment is usually not reasonable for small distributed generation.
- Transfer Trip is a method of system protection that can take distributed generation plants off line quickly and may be required for protection on lightly-loaded feeders. But Transfer Trip usually requires fiber communication, which can add cost.
 - Evaluate other protection scheme options, such as Feeder Load Monitoring or Hot-Line Blocking versus Transfer Trip where possible.
- Don't oversize equipment.
 - A transformer upgrade should only increase the capacity equivalent to the extra MVAs (MW/Power Factor) added by the generation project. Oversizing adds unnecessary cost.
 - Breakers: Although only the utility can calculate the proper breaker size required past the POI, request that breakers be sized properly. They are often conservatively oversized, particularly in the feasibility stage.
- Request metering on the low-side.
 - Metering on the high-side (the high-voltage side or utility side of the transformer) requires larger, more expensive, equipment. By metering on the low side, the utility will calculate losses incurred through the transformer (compared to direct measurement) when determining generation delivered to the utility. You'll lose some accuracy in reporting of the delivered generation, but the impact will be very small. Please note that each utility is going to have individual standards regarding this and may not be able to agree to this.



COST ESTIMATE CASE STUDY

Stahlbush Island Farms, Inc. Biogas Project

Developed by Stahlbush Island Farms (SIF), the Stahlbush Biogas Plant is a 1.6 MW power plant located in Linn County. The plant is operated as a Qualifying Facility. SIF began commercial operation of the biogas plant on June 17, 2009.

Stahlbush Biogas Plant is interconnected to PacifiCorp's 20.8 kV Peoria Circuit out of Buchanan Substation. The System Impact Study concluded that the addition of the facility to the distribution system would not create any protection or control issues. However, the System Impact Study did determine that Power Factor would be an issue (VARs or inductance created by the generator). This required the addition of 1200 kVA of switched capacitors.

The plant initially required an estimated \$222,800 of distribution system upgrades.

The System Impact Study estimated these costs:

Distribution line:	\$50,000
Distribution metering:	\$50,000
Generation site	\$68,400
Buchanan substation	<u>\$54,500</u>
TOTAL:	\$222,800

(At the Feasibility and System Impact Study stages, the cost estimates depend significantly on assumptions and previous estimates from other projects. Each line item in a cost estimate can shift up or down a little at each stage, as estimates become more informed.)

However, note the significant change of -\$32,439 in distribution line and metering cost from System Impact Study to Facilities Study. The System Impact Study assumed the need for (digital/data) communication fiber at the site. This is used to send information from the billing meter to the utility. However, at the Facilities Study stage, it was determined that a digital cellular phone could be used to remotely download billing data from the meter's data acquisition system.

The Facilities Study estimated these costs:

Distribution Line & Metering:	\$67,561 (-\$32,439)
Generation Site	\$54,496 (-\$13,904)
Buchanan Substation	<u>\$62,416 (+\$7,916)</u>
TOTAL:	\$184,473

Although the Stahlbush Biogas Plant would have gone forward under the initial estimated costs, a small project would have been halted—and this ultimately saved cost for Stahlbush, while maintaining reliability, security and speed of communication.

INTERPRETATION OF TIER-QUALIFYING CRITERIA AND THE ADEQUACY OF TIER 1 AND TIER 2 SCREENS

Although AR 521 states that “a public utility may not impose different or additional criteria,” there is no authority limiting utilities to using just the AR 521 screens to evaluate a project. Additional requirements or tests may be placed on the project by the utility.

Potential utility distribution system concerns include:

- **Anti-islanding.** If there is a persistent grid fault, then the generation must also turn off (must not island). This requires a communications/control strategy.
- **Grounding, ground-fault overvoltage.** The utility must coordinate the grounding with the ground fault protection on the grid. Surge arrestors, which limit overvoltage, may be required.
- **Short-circuit.** The utility will calculate the additional short-circuit current from the power plant, and an interrupting device upgrade may be required.
- **Protective relaying.** The distribution protective relaying may need to be upgraded due to the new power plant. The relays may need to be replaced or re-programmed.
- **Voltage flicker.** Power plants may cause the voltage to vary, which can create light flickering. This can require reactive devices (capacitors or inductors) to correct.
- **Harmonics.** Power electronics, which can be part of a solar or wind power plant, can create harmonics. Harmonic filter equipment or designs may be required.



TIER QUALIFYING CRITERIA CASE STUDY

Bellevue and Yamhill Solar Projects

A Tier 1, 2 or 3 interconnection process might be expected to be quick and efficient. However, a utility can and will require additional studies above AR 521 requirements if there is some aspect of a project that raises a concern.

Such was the case with the Bellevue and Yamhill Solar Projects. Developed by EnXco, these are among the largest ground-mounted solar installations in the Pacific Northwest, at a combined 2.85 MW and are located in Yamhill County near Salem. The solar PV power plant, which uses thin-film photovoltaic panels, is interconnected to PGE's distribution system. The plant is planned for completion in late 2011.

The developer applied separately to interconnect the two projects, using the AR 521 Tier 2 application for projects up to 2 MW.

Although not specified in the rules or procedures, the utility was concerned with the potential effect of multiple inverters on its system (solar photovoltaic projects have inverters to convert the DC power from the solar panels to AC power). PGE required field-testing because of the concern, which was an unexpected request for Tier 2 (not necessarily required by AR 521), but the results showed no cause for concern.

In addition to the multiple inverter concern, speed of reclosing was also a concern. The IEEE standard, which AR 521 follows, requires two-second reclosing, which this project could meet as specified. However, the surrounding utility system had reclosers set for less than two seconds, requiring faster reclosing of the Bellevue and Yamhill projects to match the surrounding system.

The project required this extra evaluation, and was ultimately bumped to Tier 4 because it failed a Tier 2 screen: the capacity was >15 percent of the Average Maximum Load. The project stayed on schedule and successfully completed the interconnection process.

Rules of thumb

- Before applying for a Tier 1, Tier 2, or Tier 3 interconnection ask these questions:
 - Have any other projects completed interconnection at this Tier with this utility?
 - Does the utility have any additional requirements (screens) or concerns?
 - Does the utility consider specific expensive equipment (e.g., metering) as a minor modification?
- Review any previous system studies, if available, from the utility's interconnection queue (or ask an engineering consultant):
 - Is the distribution line lightly-loaded, or at full capacity?
 - What is the average maximum load of the line?
 - Be aware that NERC requires a "critical facility" (U3 MW) to have redundant communication. To reduce cost, while maintaining reliability, security and speed, wireless communications are recommended.
- Metering cost may affect project feasibility:
 - Tier 2 projects must require only minor modifications (M\$10,000). Metering, which is required for all projects, generally costs U\$10,000 at a voltage of U600 V. Although PGE doesn't define metering as a modification, be aware that some utilities do define metering as a modification, effectively negating any Tier 2 interconnections.

If a project does not qualify, and must be bumped up to Tier 4, keep in mind that any utility evaluation thus far contributes to the Tier 4 interconnection process and there should be little delay from changing Tiers, although further study of the project may be required.



For more information, visit us online at www.energytrust.org or call at **1.866.368.7878**.