CHAPTER 8

The Technical and Economic Rules Governing Grid-Integration Interconnections and Operations

Abstract

In chapter 8 we provide a primer on basic engineering terms and concepts relevant to grid-interconnected small power producers (SPPs). We also discuss the technical and commercial rules that govern the connection and operation of SPPs on the national grid or an existing isolated mini-grid. We conclude by discussing factors to be considered when interconnecting SPP generators to isolated mini-grids.

Basic Terms and Concepts

The general term interconnection refers to all the physical equipment needed to connect a new generator to an existing grid. Key terms used to describe the points of connection involved are presented in figure 8.1.

SPP generators usually produce electricity at a lower voltage than the large generators on a grid. Typical generating voltages for small power producers are in the range of 400 volts (V)–3.3 kilovolts (kV). When integrated into a larger grid, the SPP’s power output will almost always be raised to a higher voltage, usually in the range of 11 kV–110 kV. The exact level will depend on the country’s electrical standards and the voltage level of the existing network in the area where the SPP is located.

The SPP’s last switch or circuit breaker is the point of interconnection (POI). Beyond this point, all technical matters are the responsibility of the utility. The meter that gauges the SPP’s sales to the utility that owns or operates the main grid is located at the point of supply (POS). Beyond this metering point, the ownership of the grid and the power received from the SPP rest with the utility.

In most cases, the POI and POS are adjacent to each other. In some cases, however, the buying utility designates a POS at a location that is farther upstream (toward the grid, away from the SPP) from the POI. For example, in a negotiated
power-purchase agreement (PPA), if the lines to reach the grid are long, the POS may be located where a line reaches the buying utility’s main grid. In this case the SPP, rather than the utility, will be responsible for any line losses that are incurred in transmitting electricity on the long line. The SPP will be paid for the energy that arrives at the POS and flows upstream to the utility’s grid.

Other customers, lines, or SPPs are connected beyond the point of common coupling (PCC). This point is so defined to ensure that power quality is maintained at both the PCC and beyond. Electricity grids operate at a range of voltages, usually specified in the codes that govern the grid and distribution. The line from the SPP up to the PCC may violate such specifications if there is good reason, and if the equipment can withstand such violations. Beyond the PCC, however, no such violations are allowed because other power plants, customers, and lines will be connected.

**Key Definition**

The point of interconnection (POI) is the point beyond which all technical matters are the responsibility of the utility. The point of supply (POS) is the metering point at which the SPP sells power to the utility that owns or operates the main grid, beyond which the ownership of the grid and the power received from the SPP are with the utility. The point of common coupling (PCC) is the point on the grid beyond which other lines, customers, or other SPPs are connected.

**Standardizing the Process for SPPs to Interconnect to a National or Regional Grid**

Should the process by which SPPs connect to a large grid be standardized? The answer to this question is an unequivocal yes. Allowing SPPs to connect to a regional or national grid is a new activity for most traditional utilities in...
Africa and elsewhere. At best, traditional utilities will be receptive to connecting SPPs but will have limited experience with the processes and engineering standards required to ensure efficient and technically reliable interconnections. At worst, they may be opposed to purchasing from SPPs and may be tempted to create an application process and to specify technical parameters that will make it difficult for SPPs to connect to their grids. Therefore, just as the regulator requires a standardized PPA (see chapter 6), it should also impose standardized interconnection guidelines that spell out both the application process and the mandated technical standards. Any connection and operations manual for SPPs developed by the purchasing utility should also be consistent with technical guidelines issued by the regulator. Sometime in 2014, it is expected that Tanzania Electric Supply Company (TANESCO) will release a connection and operations manual specifically designed for SPPs.

In most instances, SPPs will be relatively small in capacity, compared to the larger, utility-scale generators serving a national or regional grid. This means that the overall approach to interconnecting an SPP can generally be simpler than that for a large generator. Regulators do not have to reinvent the wheel in creating their guidelines. Standardized guidelines for connecting SPPs to larger grids now exist or have been proposed in Tanzania, Kenya, Sri Lanka, and Thailand, among many others.

Many utilities have developed and adopted a grid code and a distribution code, which describe the entire process of connecting a generating plant from first application through to on-grid operation. Depending on the voltage of interconnection allowed, the SPP interconnection may be described in either the grid code or the distribution code, in both codes, or in a separate document. In Sri Lanka, Thailand, and Tanzania, the energy ministry, regulator, or utility has developed and adopted a separate document containing guidelines for the grid interconnection of embedded generators. Regardless of where the guidelines or rules are located, it is important that those relevant to SPPs cover the (a) application process, (b) the locus of responsibility for analysis and approval, (c) payment and construction responsibilities, (d) protection requirements, (e) testing and commissioning procedures, and (f) the data exchange process and follow-up activities.

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**Key Recommendation**

Regulators should require a standardized process for SPPs that wish to interconnect to a regional or national grid. The standardized process should include specific guidelines for the application process, responsibility for analysis and approval, payment and construction responsibilities, protection requirements, testing and commissioning procedures, and a data-exchange process and follow-up activities.
Scope of the Engineering Standards for Interconnection

Engineering standards for interconnection should ensure safe and reliable operation of the grid as well as of the SPP. The interconnection should be designed and built with good-quality equipment of the correct rating and should be protected with the necessary relays. The interconnection of any generator should have standard protection facilities to prevent damage from (a) overvoltage, (b) undervoltage, and (c) overcurrent. In addition, other safety-related protection (such as protection against lightning damage) should be implemented. To meet these operating requirements, the engineering standards should spell out the relays (over- or underfrequency, over- or undervoltage, overcurrent, reverse power, and so on) that should be required for different generator types (synchronous, induction, or asynchronous) and over what size range.

Since most SPPs are small and are embedded in the distribution network, they will generally be nondispatchable. This means that the generation dispatcher on the main grid cannot (remotely or through an oral instruction) switch the SPP on or off or control how much output each SPP should produce at any given time, because (a) the resource is intermittent (such as in run-of-river hydro and wind), or (b) contractual obligations require the grid to purchase the SPP’s full electrical output at all times under “must-take” contracts. Under such contracts, if the SPP produces it, the grid must take it (see chapter 6).

SPP generators that are connected to the main grid are usually not designed to operate to serve an isolated grid that may become disconnected from the main grid, and SPPs that are embedded and nondispatchable require protection against islanding. This means that in the event of a grid failure, the SPP must quickly shut down without attempting to serve the section of the grid and its customers in the vicinity of the SPP (that is, not operating as an isolated island electrical system). This is a basic safety requirement to prevent dangerous overvoltages and other abnormal operating conditions that may damage the equipment of SPPs, the utility, and customers. Such protection against islanding can be implemented using a number of engineering techniques, including detection of over- and underfrequency, the rate of change of frequency, reverse VAr, or voltage vector shift. These relays and their application in interconnecting SPPs to a main grid are explored in greater detail in Greacen, Engel, and Quetchenbach (2013).

All the above techniques to prevent islanding depend on measuring the indirect effects of the onset of islanding, such as abnormal changes in voltages and frequency, that will then automatically cut the SPP off from the grid. An SPP with its own mini-grid or other captive load may, in rare cases, remain stable when the grid fails. This can happen only when the mini-grid load or the captive load reasonably match the power output that was delivered by the SPP when the grid failed. This is a dangerous situation, as voltages higher than the normal voltages may appear on customer supplies, and when the grid supply returns, the reconnection will most likely be out of synchronism, causing equipment damage.
A simple and definitive—but relatively expensive—technique to prevent islanding is to provide intertripping. This ensures that when a designated substation circuit breaker is tripped by the grid operator or automatically as a result of a fault on the grid—or when a main grid line has no power—the SPP will trip out and isolate itself from the main grid, so that no power will flow to the grid from the SPP. Because of the higher costs of direct communication links between the SPP and one or several points on the grid, intertripping is rarely used among SPPs.

The measurement and detection of abnormal voltages, currents, and frequency are all available now in a single digital protection relay unit. In most cases, the cost of this single relay unit will be lower than the traditional approach of using separate relays to receive measurements on each parameter to detect every abnormal condition. Such an integrated relay is likely to cost about $5,000, excluding the cost of the circuit breakers. For small induction generators (IGs), cheaper options (under $1,000) are available.

**Key Recommendation**

Engineering standards for interconnection should mandate the use of good-quality equipment with the correct ratings; protection to prevent damage from overvoltage, undervoltage, and overcurrent; protection against islanding; and protection against lightning damage and other safety hazards.

**Paying for Interconnection Costs**

Two general approaches are used in charging large and small generators for the cost of connecting to an existing grid. The first is to charge for a “shallow” connection. This approach is based on the view that any generator, whether large or small, that wishes to connect to an existing grid should pay only for the section of line and other equipment from the generator up to the POI. But if the grid does not exist in the area, a shallow connection may extend beyond the POI, and even beyond the PCC. The second approach is to charge for a “deep” connection. It presumes that the generator, large or small, should pay the shallow connection charge plus any upgrades to the upstream network that need to be made to accommodate the SPP’s output. A “deep” connection may also constitute a direct connection from the generator to a point upstream on the grid where the required capacity is available, bypassing any locally available lower-capacity lines.

If the regulator allows SPPs to pay only shallow connection charges, the remaining deep connection costs are borne by the utility. But since these remaining capital costs will be rolled into the utility’s overall capital costs at the time of a tariff application, they will ultimately be paid for by all customers on the utility’s system. This approach is sometimes referred to as the “socialization of connection costs.” The rationale for sharing the costs of the interconnection is that
upstream capacity is shared among many customers and SPPs. In addition, in some countries regulators have established mechanisms to subsequently compensate the first newly connected customer or SPP for payments made for a network connection if the connection is later used to serve other customers or SPPs.\textsuperscript{10}

If a good renewable energy resource for an SPP is far away from the closest possible POI on the grid with adequate capacity, the financial viability of the SPP project may be compromised by requiring it to pay the full cost of constructing an interconnection to the main grid. The central regulatory question then becomes who should pay the capital costs of the connection and any upgrades required upstream (if those costs are not socialized)? In Sri Lanka, more than a dozen mini-hydro SPPs in the Central and Sabaragamuwa provinces have been waiting more than five years for a grid connection because of the absence of grid capacity upstream from their closest POI. The Ceylon Electricity Board (CEB), the national utility, initially offered a cost-sharing arrangement (50 percent by the utility, 50 percent shared by the proposed SPPs) that would have required up-front payments by the SPPs. But no agreement could be reached for several years because of varying levels of commitment among the SPPs and lack of financial capacity among several. Finally, the CEB applied for and received a concessionary loan from the Asian Development Bank (a multilateral development bank that funds new infrastructure in developing countries in Asia) and built the upstream network capacity on its own. The nonsubsidized cost of this investment will eventually be paid by the CEB’s electricity customers (through tariffs). SPPs were required to pay the connection costs only up to the closest POI (that is, the shallow connection charge). It appears that a similar approach will soon be taken in Kenya. The cost of a long radial line to connect the 300 megawatt (MW) Lake Turkana wind project in northern Kenya will be paid by all customers of KETRACO, the utility that owns and operates Kenya’s transmission facilities.

In another example from Sri Lanka, four permits for wind power were issued at the same time for sites in the same area. The grid interconnection required 15–20 km lines from each power plant to reach the grid. But it was also recognized that it would be wasteful (in terms of investment and energy losses) for each SPP to build a separate 33 kV line to the closest grid point. The CEB therefore proposed a cost-sharing arrangement: The CEB would finance and build a grid substation in the vicinity of the wind resource area to step up the wind power SPP outputs to 132 kV, if the four SPPs would jointly finance the 132 kV transmission line to reach the grid. However, the four SPPs could not reach a joint agreement, so this less costly option could not be implemented. As a consequence, one SPP went ahead of the others. It financed and built a new 15 km 33 kV line to connect its 10 MW wind power plant to the grid. This 33 kV interconnection was adequate to serve only 10 MW, with no capacity for others to share the line. The other three wind power plants were built subsequently and connected to a new grid substation jointly financed and built in the vicinity of the wind resource area, while the first

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power plant continues to operate on the long connection, having now completed two years of operation.

**Should an SPP Be Allowed to Construct the Interconnection?**

As noted earlier, an interconnection is a general term that refers to all the physical equipment needed to connect a new generator to an existing grid. An interconnection will typically consist of (a) the transformers, switchgear, and protection equipment of the SPP; (b) new lines (or upgrades) and other switchgear and protection equipment to be installed farther away from the SPP (toward the POI); and (c) lines and equipment farther upstream from the POI. It is usually the case that the equipment referred to in (a) will be built and paid for by the SPP, whereas the equipment in (b) and (c) will be paid for by the SPP but built and commissioned by the utility (see table 8.1).

In expanding networks, most utilities give highest priority to expanding the transmission and distribution network to serve more customers and to connecting new, large generating plants. These are given highest priority because they are very visible and are driven by social and political pressure on the utility. Under these circumstances, which are common in many African countries, even if SPP interconnection guidelines have been issued, SPP-requested interconnections often get pushed to the end of the queue. And even if the utility wants to make a connection, it may simply not have the money to pay for upgrades farther upstream of the SPP’s POI. Therefore, it has become increasingly common for utilities to allow SPPs to build their own interconnection—consisting of lines, transformers, and switchgear—even beyond the POI. When utilities allow construction by SPPs, they typically

### Table 8.1 Cost Allocation of Interconnection Equipment Generally Observed in Asia and Africa

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Purpose</th>
<th>Paid by</th>
<th>Cost sharing</th>
<th>Built by</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transformer(s), switchgear, and line up to the POI</td>
<td>To supply power to the grid</td>
<td>SPP</td>
<td>None</td>
<td>SPP</td>
</tr>
<tr>
<td>Protection equipment</td>
<td>To protect the grid from adverse effects of the SPP and vice versa</td>
<td>SPP</td>
<td>None</td>
<td>SPP</td>
</tr>
<tr>
<td>Energy meter and metering equipment at the point of supply</td>
<td>Invoicing</td>
<td>SPP</td>
<td>None</td>
<td>Utility</td>
</tr>
<tr>
<td>Line upstream of the POI up to a designated point in the grid</td>
<td>To deliver power from the POI to the grid</td>
<td>SPP</td>
<td>May be possible, with another SPP</td>
<td>Utility (SPP may be allowed to build)</td>
</tr>
<tr>
<td>Lines and equipment farther upstream of the designated point in the grid</td>
<td>Enhance capacity of the lines and other equipment to deliver the output of the SPP to the grid</td>
<td>SPP</td>
<td>May be possible, with another SPP, a customer, or the utility</td>
<td>Utility (SPP may be allowed to build)</td>
</tr>
</tbody>
</table>

*Note: POI = point of interconnection; SPP = small power producer.*
impose one or more of the following conditions: (a) the interconnection should be based on the standard costs of the utility; (b) the material should be provided by the utility and paid for up-front by the SPP or purchased from a short list of approved suppliers of the utility; and (c) construction labor and management should be provided by the SPP, but supervised by the utility. Upon completion, the utility will test, commission, and take over the line and other equipment. The SPP’s interconnection equipment described in item (a) above will also be tested and commissioned in the presence of a utility representative, but will be maintained by the SPP.

**Transfer of Interconnection Facilities to the National or Regional Utility**

All SPP assets up to the POI remain under the SPP’s ownership. This ensures that the equipment is maintained by the SPP to deliver power safely to the grid and with the required quality. In most instances legal ownership of the SPP’s power output is transferred from the SPP to the utility at the POS, which in most cases is the same as the POI or adjacent to it.

It is common practice that customer-paid network assets or SPP-paid assets upstream from the POI are transferred to the utility at zero cost. This seems reasonable because the lines upstream carry power that is now owned by the utility. From an SPP’s perspective, this convention has both positive and negative aspects. On the positive side, the utility assumes the obligation to maintain the upstream assets and to replace them in the future when required—and no further obligations are imposed on the SPP. On the negative side, the SPP will rightly point out that an asset that it paid for is now fully owned by the utility, without the SPP receiving any direct compensation for its investment (unless the investment costs are later shared with other neighboring SPPs). As SPPs are relatively permanent facilities (compared with customers, who change locations), the mere fact that the utility takes over the ownership of upstream assets should not be of major concern to the SPP. An important advantage is that it relieves the SPP of the burden of maintenance and replacement of upstream assets beyond the POS.

**Utility Equity Returns and Depreciation on SPP-Built Interconnection Facilities Transferred to the Utility**

How should regulators treat these “gifted assets” when deciding tariffs that utilities may charge? Utilities tariffs typically earn a return on capital assets they have invested in, and tariffs they are allowed to charge also account for depreciation of these assets. As discussed in chapter 5, the utility should be allowed to take depreciation for gifted assets because they will have to be replaced at the end of their economic life, but should not be allowed to earn an equity return on these assets because they were not investments paid for by the utility. Therefore, the regulatory agency should require clear separation of assets funded by the utility from gifted assets funded by SPPs or other entities when determining investment/depreciation on network assets in order to establish the revenue levels that will be recovered through the utility’s tariffs.
Compensating the SPP for Later Use of an Interconnection

Sometimes an SPP (or even a new customer) will apply to use an interconnection that was previously paid for by another SPP. It is generally accepted that it is unfair for a later SPP or customer to get a “free ride” on assets paid for by another SPP or customer. Hence, it has become increasingly common for regulators to establish a system that requires new SPPs or users who wish to connect during a specified period of time (say, within five years of the establishment of the interconnection) to reimburse the SPP(s) or customer(s) who paid for interconnection facilities that they now seek to use. For such a reimbursement system to be successful, the utility must maintain accurate records, charge the new customers and SPPs a pro rata share of the initial capital cost, and provide reimbursement to the first customer or SPP.13

Such situations are especially likely to arise in the case of new small hydro and wind power developments. It is often the case that SPPs in the same area will secure approvals and reach financial closure on different time schedules. The first SPP may not be able to wait until all other SPPs in the area are ready to pay jointly for an interconnection. If the first SPP were forced to wait, it might run the risk of losing access to financing or other approvals having a defined expiration date. The first SPP may be willing to pay for the entire interconnection if it knows that it will be compensated when others need to use some of the interconnection capacity in the future.

A related issue is the sizing of the interconnection. For example, a 2 MW SPP can be connected using a conductor with a smaller cross-section, but it may be the policy of the utility that all medium-voltage distribution lines should be of a certain minimum size. That minimum size may be much larger than would be required for the 2 MW SPP. In this case, the SPP will overpay for capacity that it does not need. In this situation, we think that it is both fair and efficient that the initial SPP should be compensated when more customers (or SPPs) are connected over the higher capacity line.

Minimum Interconnection Voltage for Generators of Different Sizes

SPPs are usually embedded in the distribution network and connected to common distribution lines. The main reason for embedding SPPs into the distribution network is to minimize the cost of interconnection and relieve the SPP of the large capital costs that would be required to reach the high-voltage transmission network through expensive high-voltage step-up transformers and switchgear.

In deciding on an appropriate interconnection voltage for SPPs, the two primary considerations are (a) to minimize the impact on customers, and (b) to lower the cost of connections to SPPs. The general rule is to limit the size of the SPP’s generating capacity to match the current carrying capacity of the typical conductor used by the utility at that voltage level. But this cannot be considered a hard-and-fast rule. For example, a long 33 kV radial distribution line serving a town 30 km from a grid substation in Tanzania may not be able to accommodate a 10 MW SPP at the town end of the line. This is because when the SPP is
generating, the voltage at the SPP (town) end may increase above specified levels unless the customers in the town exert a demand of 10 MW or more. This voltage rise at the town end of the line may be unacceptable and could damage appliances and other electrical equipment used by customers in the town. As such situations occur frequently in Africa and Asia, where many communities and resources are located far from the grid, there are two options for utilities and regulators endeavoring to establish a policy on the interconnection voltage and the SPP capacity limit. The first is to predefine the allowed connection capacity at each voltage level (for example, 5 MW at 11 kV, 10 MW at 33 kV), to allow the utility to conduct studies on each application for interconnection from an SPP, and then to request the SPP to pay for network strengthening to enable the voltage standards to be maintained. The second is to specify only the upper limit of generating capacity allowed for SPPs anywhere in the grid, and to allow the utility to decide the connection voltage on a case-by-case basis. Sri Lanka and Tanzania generally use 33 kV as the interconnection voltage for SPPs, but 11 kV lines exist as well. The SPP capacity in both countries is limited to 10 MW per installation. Vietnam allows SPPs on 35 kV and 110 kV lines, and the SPP capacity limit is 30 MW.

**Key Recommendation**

When an SPP wishes to connect to the main grid, the following interconnection and cost-recovering policies are recommended.

1. SPPs should pay for and construct the transformers, switchgear, and protection equipment required for interconnection up to the point of interconnection (POI). They should also pay all so-called shallow interconnection costs, even beyond the POI. The regulator should decide whether other (deep) connection costs should be paid by the SPP or “socialized”—that is, paid for initially by the connecting utility and ultimately by its customers through transmission or distribution tariffs.

2. The utility should, in principle, construct the new lines and other upstream equipment on the grid beyond the POI and install the meters and metering equipment at the point of supply (POS). As a standard policy, to ensure timely construction, the SPP should be allowed the option to construct facilities beyond the POI under construction and engineering standards established by the utility and subject to review by the regulator.

3. SPPs should retain ownership of their assets up to the POI but transfer ownership of SPP-paid assets upstream of the POI to the utility at zero cost. The utility can claim depreciation on these assets but should not earn a profit on such “gifted” facilities.

4. New SPPs or users who wish to connect to interconnection facilities paid for by another SPP or user should reimburse the initial SPP(s) or customer(s). In these cases, the utility must maintain accurate records, charge the new customers and SPPs a pro rata share of the initial capital cost, and provide reimbursement to the first customer(s) or SPP(s).
Successful Integration of SPPs into the Grid: Technical and Commercial Requirements

Once SPPs come online, whether by being connected to the main grid or by operating on an isolated grid, they must satisfy certain operating practices and maintain several key electrical parameters in order not to cause physical harm to others and themselves. Regulators, who are often not electrical engineers, cannot be expected to develop the required operational technical codes. Instead, the job of the regulator should be to make sure that such a code is created (if it does not exist) and is agreed to by both the main-grid operator and the SPP operators. If there are disputes, the regulator, with the support of technical advisors, must quickly resolve them. In this section, we provide a brief primer on what should be included in such a technical code, as well as a checklist for preparation of the code.16

Do SPPs Need to Be Dispatchable?

Grid-connected SPPs that are powered by renewable energy or are part of a cogeneration scheme where both electricity and steam are produced generally need not receive dispatch instructions from the system operator (also known as the dispatcher). In other words, these SPPs are generally not dispatchable. This is because renewable energy is intermittent and may not be available for dispatch at any given time. Similarly, a generator in an industrial cogeneration facility generates electricity according to the industrial heating (steam) needs of the industrial process. For these reasons, and because SPPs are small compared to other generators on the grid, most SPPs have “must-take” PPAs that allow the SPP to generate at the SPP’s convenience and require the utility to purchase all of the electricity generated (see chapter 6).

But there are exceptions to this general rule, especially when the number of SPPs in the network grows and begins to have a significant impact on the grid. For example, in some rare cases in the United States where large concentrations of wind power are found and at times when the transmission system is congested or there is an excess of water in hydropower reservoirs that must be released, wind power generators are ordered to curtail power generation (that is, not generate electricity). Also, when a system has a lot of wind power generation in the same geographic area, some dispatch (or control) will be required to ensure that a sudden increase or decrease in wind speeds that would lead to increases or decreases in the electrical output of wind generators does not cause instability in the grid.17 Small hydropower plants, even if they are run-of-river, have a more stable and predictable pattern of production. Normally, small hydropower systems provide adequate time for other generators in the system to respond to changes in hydropower production.

In such cases, the contract between the SPP and the main-grid operator may allow for dispatch, even when the SPP resource is renewable and intermittent. In these cases the generation dispatcher will have the ability and authority to decide when to operate the power plant and the level of output at which it
should operate. To perform these functions, the generation dispatcher will require information on the status of the resource (water availability, rainfall, wind speed, and so on) and the degree of readiness of the power plant to start up (ready to start, on standby, under long-term maintenance). This information may be obtained from the SPP either manually (by telephone or fax) or online (through an automatic data acquisition system). The contract permits and dispatch instructions (stand by, start up, shut down, raise or lower power output) may be issued either manually (by telephone or fax) or remotely (through a supervisory control system). For this to be possible, hardware must be installed at the SPP. The hardware at an SPP for an automatic data-acquisition system may cost about $20,000, in addition to which will be the cost of the monthly or annual fee for the communication link. A supervisory control system may cost about $30,000 in addition to the fees for the communication link. For both a data-acquisition system and a supervisory control system to be functional, the dispatch center will need to be equipped with the necessary hardware and software to analyze the acquired data and optimize the grid operating costs. Such supervisory control and data-acquisition systems will generally be too expensive for small SPPs. Hence, the norm in most countries is for SPPs to be nondispatchable.

As an alternative to dispatch, SPPs can be incentivized to generate electricity at different times through pricing mechanisms. For example, Thailand and Vietnam pay renewable energy generators according to a time-of-day (TOD) rate, with higher tariffs during work-week daytime hours and lower payments at night, on weekends, and on holidays. To respond to such TOD tariffs, it may be advantageous for some SPPs to have storage, such as a pond in a mini-hydro power plant or stockpiled biomass fuel. For intermittent renewable energy like solar and wind power, higher TOD rates may coincide with their periods of peak production: the sun shines and the wind blows most strongly in the daytime—typically the peak rate or a daytime rate in a TOD tariff schedule. In Sri Lanka and Tanzania, SPPs receive a lower tariff during the rainy season and higher payments during the dry season. In Tanzania, this incentivizes maximum production to help alleviate strain on hydropower resources. (For more on this, see the discussion of feed-in tariffs in chapter 7.) Even if storage were limited or not available, such TOD tariffs would encourage SPPs to schedule maintenance during the off-peak period (Thailand and Vietnam) or the rainy season (Sri Lanka and Tanzania).

**Essential Electrical Parameters to Be Specified and Controlled**

Four major electrical parameters need to be specified and controlled for successful integration of SPPs into the grid: voltage, frequency, harmonic distortion, and the power factor.

**Voltage**

The output voltage of the SPP facility should be equal to the nominal (usual) voltage of the grid. Most countries require the same voltage standard on the
main grid and mini-grids so that machinery and appliances need satisfy only a single uniform voltage standard throughout the country. For a grid-connected SPP, the voltage regulation (the variation in voltage between full power and zero power output) at the POI should be within specified limits. For example, most countries establish a voltage regulation standard of ±6 percent on the low-voltage network and ±5 percent on the medium- or high-voltage network. Voltages that are outside this specified band are harmful to the SPPs, to utility equipment, and to customers’ equipment. Under emergency conditions, such as the temporary outage of a transmission line that shares power at normal times, a voltage regulation of ±10 percent is allowed in most countries for a short period of prespecified duration.

**Frequency**

The normal operating frequency of the SPP is the same as the frequency of the national grid (either 50 hertz [Hz] or 60 Hz). SPPs will follow the grid frequency, and because they are small, the presence or absence of a single SPP at any given time will not make any impact on the frequency of the main grid. In contrast, the loss of a large generator feeding the grid will cause the grid frequency to drop. If not balanced quickly with additional generation or a reduction in customer loads, or both, the loss of a large generator may lead to large frequency drops, causing other remaining generators to trip out (for their safety). If this happens, there will be a cascading failure in which all the remaining generators stop generating electricity one by one, and the entire system will experience a blackout.

SPPs are affected by changing grid frequency in three principal ways. First, if the value of the frequency or the rate of change of frequency passes the preset threshold, based on the protection systems installed, the SPPs will trip themselves off the grid. Second, prolonged operation at off-nominal frequency may not be permissible for certain SPPs, especially those generating electricity from a steam cycle or from combustion turbines, because it could damage the turbines. Third, when the grid undergoes a frequency variation because of a disturbance (for example, the loss of a large generator or of a transmission line), even if the grid has not yet failed, automatic or semi-automatic protection for underfrequency and rate-of-change of frequency may cause SPPs to trip out, thus worsening the crisis on the grid (if the grid frequency is decreasing) or helping it to recover (if the grid frequency is increasing). Therefore, the threshold below the nominal frequency is set at a larger percentage shift compared with the upper threshold: for example, the setting’s high frequency threshold may be nominal frequency plus 4 percent, with a low frequency threshold of nominal frequency –6 percent. The rate-of-change-of-frequency protection is typically set to operate at 2.5 Hz per second, to ensure that it responds only to very severe frequency changes, such as with the onset of islanding. Frequency protection should not respond to normal changes in grid frequency from which the grid is likely to recover through other means.
In the mini-grid case, the SPP represents a large portion (sometimes 100 percent) of the generation serving the mini-grid. Here the SPP must control the rotational speed of the generator’s prime mover (steam turbine, reciprocating engine, or other) to keep frequency within limits. In small grids, frequency variations are generally allowed and are expected to be larger than the trip settings on SPPs connected to the national grid, for example ±10 percent.

**Harmonic Distortion**

The voltage of an alternating current (AC) electricity supply should be a perfect, smooth, sinusoidal waveform. Ripples and distortions in this waveform are referred to as harmonic distortion or “harmonics.” Harmonic distortion may be caused by SPPs that use power electronic devices such as inverters (in solar photovoltaic [PV] systems) or sometimes from small rotating generators. Harmonic distortions, if injected onto the grid in large quantities, may damage the electrical equipment of customers. Therefore, grid operators must specify maximum limits for harmonic generation by SPPs. Harmonic-related specifications are standard on any well-run electrical system, and grid or distribution codes generally provide comprehensive guidelines on the allowable levels of harmonic distortion and the methods of measurement.

**Power Factor**

The power factor is a measure of the degree to which current and voltage at a point in an AC electrical system rise and fall in phase. Devices that contain coils of wire (for example, most motors or all transformers) cause the current to lag behind the voltage (called “lagging power factor”). Lagging power factor lowers voltages and consumes “reactive power.” Conversely, devices that have significant capacitance (rarer in SPPs) cause current to lead voltage (called “leading power factor”). Leading power factor increases voltage and creates reactive power. When current flows out of phase with voltage, losses in the system increase.

When a synchronous generator (SG) operates at a power factor close to 1 (phase angle zero degrees), it provides the minimum or zero “reactive power” to the grid. SPPs using SGs can control their operating power factor by controlling the field current in the generator. By increasing the field current, an SPP using an SG can deliver more reactive power to the grid in order to regulate the voltage at the node at which it connects to the grid.

Grid operators or dispatchers often complain about the absence, in PPAs with SPPs, of adequate provisions governing reactive power support during day-to-day operation. They contend that in the absence of such provisions all of the grid’s reactive power requirements must be provided by other generators. But this ignores the fact that producing reactive power in generators, especially in generators (including SPPs) serving a grid through long
lines, can be a wasteful exercise. This is because providing reactive power requires currents larger than the currents required to deliver the useful output of an SPP to the grid. These larger currents cause additional losses in SPP generators, as well as in the utility’s own generators, both before and after the POS. Reactive power can be produced by other means, the cheapest being the installation of capacitors closer to the locations in the grid where such reactive power is required (for example, at transformers and on customers’ premises). A good system for managing reactive power would enable all generators (not only SPPs) to produce the minimum currents, thus minimizing heating losses across the network. Therefore, while SPPs may be required to be capable of operating at a power factor of up to 0.8 to serve any reactive power requirements of the grid under emergency conditions, the correct practice in most cases will be to operate the SPP at or close to a power factor of 1.

A special case related to the power factor involves induction (that is, asynchronous) generators, which are increasingly used in SPPs. Unlike SGs, asynchronous generators cannot produce reactive power. In fact, they require magnetizing power (that is, reactive power) to be provided externally, from the grid or by other means, similar to a customer’s induction motor.

But an SPP using an asynchronous generator can, by installing capacitors, “generate” the required reactive power to provide magnetization to the SPP’s own IG without drawing power from the grid. If the SPP does not install capacitors, however, it must draw reactive power from the grid. Grid codes or distribution codes typically specify a limitation—and penalties for such use of reactive power from the grid. These may be in the form of a limit on the operating power factor (such as a limit of 0.98 lagging to 0.98 leading), a penalty for violating the operating power factor limits, a reactive energy charge (measured in kVArh), or a combination of all the above.

**Operational Communications between Utility and Operator**

As described earlier, SPPs are mostly embedded and nondispatchable. In such cases, in principle, there is no need for any communication between the grid dispatcher and the SPP during operations. Many SPPs operate on this basis: neither party has real-time information about the operating status of the other party’s system. In Sri Lanka, where more than 120 SPPs (mostly mini-hydro) are in operation, with a total capacity exceeding 230 MW on a grid that has a peak demand of about 2,200 MW and a minimum nighttime demand of about 900 MW, there is currently no communication (on- or offline) between the SPP and the main grid system operator. At present, not even the SPPs’ day-ahead or week-ahead plans or their power plant maintenance schedules are exchanged with the dispatcher. Outages for line maintenance are coordinated at the distribution level. While no serious problems have occurred because of the absence of online communication systems on operational status, the addition of wind power into the system has introduced the requirement that specific online
status information be provided to the dispatch center. As wind flow varies significantly at shorter intervals when compared with variations of water flow in a river, frequent changes in wind power output and voltage flicker (frequent ups and downs) have been observed along the distribution lines in the area where the first few wind SPPs were located in Sri Lanka. Online communication and data acquisition from wind power plants have since been specified as a requirement.

With mobile telephone coverage now extending to many parts of Africa and Asia, and with the availability of communication interfaces in the current generation of automatic meter reading (AMR) meters used to measure SPP energy inputs to the grid (for invoicing purposes), it has become simpler and less expensive to provide online status and output information. As the SPP contribution to total output grows, especially in wind and solar, the grid operator will benefit from knowing the operational status of distributed generation (DG) in order to make forecasts and ensure that other large generators on the grid will be used in an optimal manner. Future SPP agreements are likely to move away from “must-take” regimes to some limited form of control and dispatchability. The availability of online operational information to both the dispatcher and the SPP will enable the two parties to move toward better use of resources and investments.

**Grid-Connected SPPs: Key Elements of a Good Billing and Payment System**

A meter fixed at the POS measures the energy sent to the grid by the SPP and, ideally, power imported from it. Newer meters are digital and record all important electrical parameters (current, voltage, real and reactive power, and maximum demand, at intervals of a few minutes). Now it is common to use four-quadrant meters that can measure and record the direction and combinations of two key parameters: real and reactive power and imports and exports. Meters must satisfy the appropriate standards applied by the utility to its customers. The accuracy of meters is usually specified as class 0.2 (meaning the accuracy is ±0.2 percent).

Most meter manufacturers provide a communication interface that allows for remote reading by the utility. Utilities are moving away from reading meters at the site, using AMR meters instead, which can be queried from utility offices. In developing countries, this trend is presently limited to bulk customers. Some SPP agreements may require joint reading of meters by the utility and the SPP, which might require a physical visit to the site.

Both the import and export registers of the meter are jointly read by the utility and the SPP, and the invoice for export is prepared by the SPP accordingly. The utility prepares an invoice for imports by the SPP (that is, backup power) from the grid. Thereafter, the usual payment systems follow, as in the case of any other independent power producer (IPP) (export) or bulk customer (import) of the utility—unless the utility has created a special backup tariff for SPPs (see chapter 6).
Key Recommendation

When SPPs prepare to connect to the main grid, the following technical and commercial requirements are recommended:

1. Grid-connected SPPs should not be required to be dispatchable, except in the rare case when the share of renewables on a grid reaches a high enough threshold to require dispatchability. In lieu of dispatchability, regulators and utilities can incentivize SPPs to generate electricity at certain times of the day or in certain seasons.
2. The regulator or grid operators should specify standards for voltage, frequency, harmonic distortion, and power factor.
3. Grid operators do not necessarily need to be able to contact SPPs that are embedded in the grid at the distribution level and that are nondispatchable, but as SPP penetration grows to high levels the grid operator will find it increasingly useful to know the SPP’s operational status, make forecasts, and use other generators in the grid in an optimal manner.

Factors to Consider When Connecting to an Isolated Mini-Grid with Existing Diesel Generators

SPPs connected to mini-grids with existing diesel generators present a separate set of technical and financial issues that are generally more challenging than those for SPPs connected to the main grid. At the core is the question of how the timing of the availability of electricity from the SPP coincides or overlaps with the timing of loads on the mini-grid, and how the SPP operation can be coordinated with the operation of existing diesel generator(s).

The Case of an SPP Connected to the Main Grid

To conceptualize these issues, first recall that in the case of SPPs connected to the main grid, the SPP is a small fraction of the total installed capacity of the grid. The SPP is essentially injecting current into a grid whose frequency is controlled moment to moment by much larger generators. Typically this “frequency control” function is handled by load-following generators—often large hydropower or natural-gas-fired turbines that can adjust their power output instantaneously in response to fluctuations in demand for electricity. The grid is able (except in rare instances) to absorb all the power that the SPP is able to generate. The SPP coming online or going offline causes only very small changes in power input requirements for larger generators and is generally lost in the “noise” of minute-to-minute or hour-to-hour variations in national load.

The Case of an SPP Connected to an Existing Isolated Mini-Grid

This situation should be contrasted with an isolated mini-grid where the capacity of an SPP generator is significant with respect to the total load on the grid.
Here we run into several difficult issues. We will start with the financial issue, and then move onto technical issues (which have financial implications).

**When Demand Is Less than the Small Power Producer’s Capacity**

The fundamental financial issue is perhaps easiest to conceptualize: If there are times of day when load on the mini-grid is lower than the amount of electricity that the SPP can generate, then the SPP cannot generate to its full production capacity. Because the SPP's capacity will not be fully utilized, it will not be receiving full revenue. This represents a shift from the “must-take” contractual arrangement of SPPs on the main grid (described in more detail in chapter 6) to one in which electrical energy can be sold only if someone on the mini-grid is demanding it at that moment. This temporal discrepancy between the ability to supply and the availability of demand is one reason why tariffs for SPPs selling to existing utility-owned isolated mini-grids in Tanzania are much higher (about three times higher) than for SPPs selling to the main grid.

PPAs for SPPs connected to a utility’s isolated mini-grid should take this into account. One possible way to do this is to include in the PPA general language such as the following:

> The Buyer has no obligation to purchase and accept the portion of electric energy from the Seller when said energy would exceed the amount of power that the Buyer’s mini-grid system can safely accept while maintaining overall power quality to customers.

**Complicating Technical Factors**

The engineering realities of keeping electrical systems stable and power quality acceptable (alluded to in the sample PPA text above) present further challenges and constraints that complicate and exacerbate the fundamental financial issue raised above.

The main issue is that in mini-grids it is necessary to determine who is responsible for frequency and voltage regulation. The situation is analogous to that of a musical group: someone needs to keep time and set the beat. If there are multiple generators in charge they may end up working against one another—and the music will not be pretty.

Another constraint that arises specifically with diesel generators is “wet stacking.” Diesel generators, whether powered by diesel fuel or some other fuel such as biogas, build up residues inside the cylinders and condensation in the exhaust if operated at low loads. For these reasons, vendors of diesel generators do not like to see their products run at low load—because doing so may have implications for maintenance and warranty service. A related issue is that diesel generators are less efficient at low loads. An SPP that injects electricity into the grid may force the diesel generator to operate at levels at which efficiencies are low, and the diesel generator will be forced to consume more fuel per kWh than if it were operating at higher loads. This has the effect of reducing the diesel fuel-saving benefit of the renewable energy SPP generator. In cases in which the mini-grid diesel is owned by an entity separate from the SPP (a utility, for
example, as is the case for 16 mini-grids in Tanzania), these operating issues can complicate the relationship between the SPP and diesel mini-grid operator.

Views of Engineers
To further complicate all of this, experts disagree on the question of how much DG can be integrated into a diesel mini-grid. Here are responses from several experts:

British Columbia. “As far as I can tell PV can be added with relatively constant incremental benefit until there is spillage. And then the spillage starts to affect the economics of additional increments of PV. I’m not sure there are any obvious technical limitations.” —Brett Garret, power system engineer, BC Hydro

Thailand. “The [diesel] generator maker and synchronization panel for the DG integrator told me that they do not want their generator operating below 20 percent of [the diesel generators’] rated capacity.” —Dr. Wuthipong Suponthana, mini-grid designer

Hawaii. “The bigger issue with high penetrations of PV is frequency control. That requires some detailed modeling with models that can look at transient responses. It depends on the rotating inertia of the generator, the type of generator (electronic control, turbo, etc.), and the physical layout of the grid and the PV system. It also depends on the frequency tolerances of the system. Lanai, Hawaii, put 1.4 MW of PV in a single array on their 5 MW system and can’t run it at more than half capacity while maintaining their desired frequency stability. They are putting in a big battery bank now. It would have helped a lot if they had spread the PV out, but Hawaii has a lot of fast-moving patchy clouds.” —Dr. Peter Lilienthal, president and CEO of HOMER Energy

Tanzania. “To prevent [power quality problems] total export capacity ceilings have been established for certain types of SPPs connected to TANESCO Mini Grids:

- Synchronous generator (SG): Export capacity must not exceed 75 percent of the TANESCO’s Mini Grid’s total installed generating capacity;
- Wind farm/turbine must not exceed 50 percent of the TANESCO’s Mini Grid’s total generating capacity;
- Induction generator (IG): Must not exceed 50 percent of the TANESCO’s Mini Grid’s total generating capacity; The project’s generating capacity must not exceed 1 MW;
- Inverter-based DG: May not exceed 50 percent of the TANESCO Mini Grid’s total generating capacity.” (TANESCO 2011)

Greece. A simulation study of adding solar arrays to a diesel-powered mini-grid on the island of Kythnos assumed five 450 kilovolt-ampere (kVA) generation sets. The simulation finds “the system is generally stable for penetration levels lower than 50 percent while it becomes unstable at higher levels of penetration due to
insufficient spinning reserve of the diesel generators” (Rikos, Tselepis, and Neris 2008, section 3).

Key Recommendation
When an SPP prepares to connect to an existing isolated mini-grid that has been powered by one or more diesel generators, the following technical and commercial requirements are recommended:

1. The receiving grid should have no obligation to purchase and accept electric energy from the SPP if the energy exceeds the amount of power that the receiving mini-grid system can safely accept, while maintaining overall power quality to customers.
2. Only one of the two entities should be responsible for maintaining the nominal voltage and frequency of the isolated grid.
3. The existing diesel generator and incoming SPP must reach an agreement about how to compensate the diesel generator if the incoming SPP electricity forces the diesel generator to operate at a lower load, thereby reducing its efficiency and incurring higher costs, and potentially causing damage. A better solution would be to encourage one of the two parties—the SPP or the entity that owns the diesel generator—to assume ownership and operating responsibility for the entire isolated mini-grid system.

Two Technology-Specific Examples
Let us develop these ideas a bit further through consideration of two examples.

Example 1: Integration of a Solar PV Array with a Diesel-Powered Mini-Grid
Consider a mini-grid with a 1 MW diesel generator. Imagine that current peak load is 700 kW (figure 8.2), and this peak load occurs mostly in the evening time as people light their homes, cook dinner, and watch TV or listen to the radio.

Figure 8.2 Hourly Load Profile for Example Village Mini-Grid System

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The minimum load in this hypothetical case might be only 80 kW, occurring between 2 am and 4 am, but the daytime load is also quite low, with a minimum of only 100 kW because most people are outside working. Let us assume that this village does not include large intermittent loads such as arc welding equipment. Assume that an SPP developer wishes to add a solar electric system that interconnects to the mini-grid through an inverter. How big a system could be accommodated by the mini-grid?

A solar PV system up to 50 percent of minimum daylight hour load (50 kW in this example) would probably have minimal integration issues. The maximum output of the solar PV system is less than minimum daytime customer load, and most diesel generators can provide frequency and voltage control in this regime. The existence of arc welding or other large intermittent daytime loads could complicate this arrangement as would fast-moving patchy clouds, which would cause rapid ramp-up/ramp-down in power production from the PVs. This is because such intermittent loads would force the diesel generator to make rapid relative changes in power output to keep electricity within frequency specifications.

Approaching 100 percent of minimum daytime load (100 kW in this example), however, we run into the issue that the diesel generator is now operating with zero load but still trying to modulate frequency and voltage. This is a recipe for instability. If the customer load were to decrease even momentarily below PV power output, the PV panel would need equipment that allows it to take over the role of frequency and voltage regulation and to spill power generated in excess of load. Otherwise, these conditions could cause voltage or frequency disturbances that could cause the generator to shut off, inverter equipment (which converts direct current [DC] electricity to AC electricity) to shut off, or cause problems with customer equipment.

A solar PV installation with capacity above 100 percent of minimum daytime load would generally include a battery bank to absorb peaks when generation exceeds load. If a battery was put in place, typically it would be accompanied by an inverter that has stand-alone capability: providing frequency and voltage regulation so that the PV/battery/inverter system can carry the load entirely, allowing the diesel generator to shut off entirely at times.

With the addition of batteries it is also possible to store a portion of electricity produced by the diesel generator, allowing the diesel generator to operate at full capacity for a shorter duration producing electricity for load and to charge the battery simultaneously. This increases diesel efficiency by operating at closer to full capacity and reduces the diesel generator’s run time. If one is interested in optimizing the cost-efficiency of the entire hybrid mini-grid system (and not just the SPP generator as a private sector merchant generator selling electricity to a utility owned mini-grid) it makes sense to optimize the sizing of the battery bank capacity and renewable energy source to minimize overall levelized cost of energy—taking into account the temporal characteristics of the load profile and renewable energy resource. Free software such as HOMER\textsuperscript{25} can facilitate these calculations by modeling...
economic dispatch of different-size generators under many different candidate system configurations.

**Example 2: Micro-Hydro SPP Added to an Existing Diesel Mini-Grid**

Somewhat similar issues arise in the case of an SPP micro-hydropower generator added to an existing diesel grid. Again, the key issue is which generator is going to be controlling frequency regulation. Using the same load profile (figure 8.2), we can imagine the following:

A micro-hydro system providing up to 80 percent of minimum load would be able to run at full power continuously, injecting current to the diesel mini-grid and reducing diesel usage. System-interconnection equipment need only comprise equipment to synchronize the micro-hydropower project with the grid (if a SG) and basic over/under frequency and over/under voltage relays.

Beyond this level, but still below peak load, the micro-hydro generator would need two sets of controls: one that allows it to operate in stand-alone mode with the diesel generator off, and one in which it can synchronize to the diesel. The stand-alone controls include a regulator that controls frequency either through modulating the volume of water flow to the turbine (electro-mechanical controls) or an electronic diversion load controller that keeps frequency constant through dumping excess electricity generation to a “ballast load”—essentially a heater.

In this regime, at certain times (for example, the middle of the night or morning time), the micro-hydro is sufficient to carry the load, but the diesel generator is turned on to supplement the hydro to meet the peak for evening loads. The coordination between these two modes would need to be worked out.

If the micro-hydro is larger size, for example, to meet peak loads, then the predominant mode for the micro-hydro would be stand-alone operation. But the ability for a diesel generator to synchronize would be useful—for example to meet peak loads in the dry season.

**The Need for Operating Protocols**

Clearly, many of these cases require specialized equipment, as well as coordinated operation protocols between the renewable energy operator and the diesel operator. These complicate a financial picture already compromised by energy sales that are less than optimal because of hourly and daily variability in the load. Whether or not higher tariffs in a mini-grid case (as is the case in Tanzania) are sufficient to make up for these factors requires careful consideration on a case-by-case basis.

Coordinating voltage and frequency regulation presents challenges for which there is no one-size-fits-all technical solution. It depends on the intermittency of the renewable energy source, the presence or absence of storage (batteries, and so on), the technical characteristics of the generator, and the control system that monitors and supervises different elements in the system. These various factors have to be studied by competent electrical engineers in the context of the specific project, and the solution will require both technology as well as an operations protocol. It is unrealistic to expect that a regulator can or should write regulations to cover these many site-specific technical coordination issues.
These technical issues arise whenever there is a sufficiently large intermittent energy source combined with a diesel generator. If the diesel generator is owned and operated by the same party as the intermittent renewable energy source, then these issues are internal to the developer. It is more difficult to resolve these problems when the SPP is owned by a different party than the owner of the diesel generator and mini-grid. Therefore, the best solution would be to encourage one of the two parties to take over ownership and operation of both the renewable and diesel generators.

The challenges of dispatch, frequency, and voltage regulations would further multiply in the event that more than one company is operating SPPs on a single mini-grid. It may be most practical to allocate full rights of the market in a particular mini-grid to the first project on that mini-grid that passes certain milestones, such as signing a PPA or obtaining a letter of intent.

Notes

1. In general, the grid code covers the transmission network and associated generators, equipment, and customers, while the distribution code covers the network and equipment downstream of the transmission network. The “grid” refers to the entire network, both transmission and distribution. Specific definitions of transmission and distribution depend on the standard voltages used in a given country. In Tanzania and Sri Lanka, the network above 33 kV is the transmission network, and the balance is the distribution network. In Thailand and Vietnam, 110 kV and above is considered to be the transmission network.

2. A proposed Tanzania Guide for Grid Interconnection of Embedded Generation, which was developed by the regulator, is available in three parts here: http://www.ewura.go.tz/sppsselectricity.html. Tanzania’s utility, TANESCO, also has a grid code specifically addressing SPPs (available from TANESCO) that is expected to be issued in 2014. Sri Lanka’s guidelines (in two parts) are available in English upon request from the Ceylon Electricity Board. Key features of Thai regulations (in English), are available at: http://www.eppo.go.th/power/vspp-eng/index.html.

3. A relay is a device that receives and processes a measured quantity, such as the voltage on a line, and then issues a signal to activate a device such as a switch, a warning indicator, or an alarm. A relay can be programmed to make certain calculations with the measured quantity and to issue the output signal based on the results of the calculation. A relay can also be programmed to issue the output after a time delay.

4. Synchronous generators (SGs) rotate in phase with the rest of the SGs on a grid. Asynchronous generators rotate typically between 0.5 to 2 percent faster than the SGs on a grid. An induction generator is effectively the same as the induction motor very widely used in industry to convert electricity to motive power; when working as a motor, it rotates below the synchronous speed, and as a generator, it rotates above the synchronous speed.

5. These issues are discussed in sections B7 to B9 in the Tanzanian guidelines mentioned in footnote 2.

6. Reverse flow of reactive power from the grid into the SPP.

7. Captive load refers to load that is on the SPP’s side of the meter.

8. Tripped: switched open so that no current can flow.
9. Depending on the distance between the utility and SPP breakers, an intertripping system may cost about $10,000 or more to install, plus a monthly fee for the communication link.

10. A good survey analysis of the issues surrounding transmission charges for new renewable generators can be found in Madrigal and E3 (2010). For the most recent statement of the Sri Lankan regulator’s policy on sharing of transmission investment costs between a first and later SPP, see http://www.pucsl.gov.lk/english/wp-content/themes/pucsl/pdfs/methodology_for_charges.pdf.

11. This provides assurance to the utility that the material used will meet its technical standards. This is an important utility concern because the interconnection (or a portion of it) would subsequently be owned and operated by the utility.

12. Such decisions are usually taken on a case-by-case basis.

13. Sri Lanka has recently approved such a reimbursement to the first customer or SPP (PUCSL 2010). Up to nine customers/SPPs pay 10 percent of the first customer’s shallow interconnection cost if they request connection within the first five years of operation of the interconnection asset.

14. For example, on a short 11 kV line in Tanzania, it may be possible to deliver 10 MW to the grid, without being bound by a predefined regulation (for example, a regulation that capacities over 5 MW should be connected to 33 kV lines).

15. In Tanzania, the 10 MW limit is for exported capacity, while the installed capacity and the actual generation may be higher than 10 MW.


17. Instability may be caused by a shortage or surplus of power on a grid. Unless arrested, a shortage or a surplus of power may lead to a cascading failure of other generators on the grid.

18. May also be referred to as time of use or TOU rates, which are applicable to electricity customers.

19. Islanding is a situation in which an SPP and a segment of the local distribution network would isolate from the main grid and continue to operate as an “island” within a grid.

20. Solar PVs produce direct current (DC), whereas all grids operate with alternating current (AC). DC is converted to AC using an inverter. Smaller generators typically used in SPPs may also cause harmonic distortion when compared with large, utility-scale generators that have more stringent specifications.

21. Reactive power (measured in kVAR or MVAR) is the portion of power flow in a circuit that is temporarily stored in the form of electric or magnetic fields in a circuit. Reactive power cannot contribute to useful work, but it does contribute to increased current flow on wires and transformers. Utilities try to minimize reactive power flow and measure and charge industrial customers for the reactive power consumed by their loads. Devices with large coils of wires such as transformers or motors consume reactive power. Reactive energy (measured in kVArh or MVARh) is reactive power used over a period of time.

22. Import and export of both real and reactive power flow across the POS provide a combination of four “quadrants.”

23. An SPP may import power from the grid, for use in the power plant during periods of low generation or during a maintenance shutdown. An SPP with a captive load
(such as a cogeneration SPP in a sugar industry or a mini-hydro SPP in a tea factory) may also import when the SPP generation is inadequate to meet the requirements of the industry. The issues for pricing of backup power are discussed in chapter 6.

24. Without proper frequency and voltage regulation, equipment powered by electricity either fails to function properly or is damaged. In Africa frequency is typically regulated at 50 Hz, with household voltage regulated at 220, 230, or 240 volts.


26. Biomass or biogas generators would have essentially the same characteristics as this micro-hydro example.

References


