MINI-GRIDS AND ARRIVAL OF THE MAIN GRID
LESSONS FROM CAMBODIA, SRI LANKA, AND INDONESIA
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ESMAP Global Facility on Mini Grids
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Cover Photo: ©Christopher Greacan
Transformer connecting the previously isolated 12 kW Athureliya micro-hydropower project to Sri Lanka’s national utility Ceylon Electricity Board

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## CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Pages</th>
</tr>
</thead>
<tbody>
<tr>
<td>FOREWORD</td>
<td>i</td>
</tr>
<tr>
<td>ACKNOWLEDGMENTS</td>
<td>iv</td>
</tr>
<tr>
<td>ABOUT THE AUTHORS</td>
<td>v</td>
</tr>
<tr>
<td>ABBREVIATIONS</td>
<td>vi</td>
</tr>
<tr>
<td>EXECUTIVE SUMMARY</td>
<td>vii</td>
</tr>
<tr>
<td>1</td>
<td>INTRODUCTION</td>
</tr>
<tr>
<td>1.1 Country Overviews</td>
<td>1</td>
</tr>
<tr>
<td>1.2 Options for Previously Isolated Mini-Grids</td>
<td>2</td>
</tr>
<tr>
<td>1.3 Scope of This Study</td>
<td>3</td>
</tr>
<tr>
<td>2</td>
<td>CAMBODIA: FROM ISOLATED DIESEL MINI GRIDS TO DISTRIBUTION FRANCHISEES</td>
</tr>
<tr>
<td>2.1 Powering Households before a Village Is Connected to the Main Grid</td>
<td>4</td>
</tr>
<tr>
<td>2.2 Regulatory Framework for Isolated Mini Grids</td>
<td>5</td>
</tr>
<tr>
<td>2.3 What Happened after the Main Grid Arrived?</td>
<td>7</td>
</tr>
<tr>
<td>2.4 Concluding Observations</td>
<td>12</td>
</tr>
<tr>
<td>3</td>
<td>SRI LANKA: TRANSITIONAL COMMUNITY-OWNED MINI GRIDS</td>
</tr>
<tr>
<td>3.1 Powering Households before a Village Is Connected to the Main Grid</td>
<td>14</td>
</tr>
<tr>
<td>3.2 What Happened after the Main Grid Arrived?</td>
<td>18</td>
</tr>
<tr>
<td>3.3 Technical Aspects of Interconnection</td>
<td>22</td>
</tr>
<tr>
<td>3.4 Concluding Observations</td>
<td>23</td>
</tr>
<tr>
<td>4</td>
<td>INDONESIA: PIONEERING GRID-INTERCONNECTION OF MICRO-HYDROPOWER MINI GRIDS</td>
</tr>
<tr>
<td>4.1 Micro-Hydropower for Village Electrification</td>
<td>25</td>
</tr>
<tr>
<td>4.2 Regulations Facilitating Grid Interconnection</td>
<td>28</td>
</tr>
<tr>
<td>4.4 Why Have So Few Micro-Hydropower Projects Been Converted to Small Power Producers?</td>
<td>32</td>
</tr>
<tr>
<td>4.5 Concluding Observations</td>
<td>33</td>
</tr>
<tr>
<td>5</td>
<td>CONCLUDING OBSERVATIONS</td>
</tr>
<tr>
<td>5.1 When the Grid Arrives, Community-Owned Mini Grids Generally Stop Selling Self-Generated Electricity Directly to Retail Customers</td>
<td>38</td>
</tr>
<tr>
<td>5.2 Few Isolated Community-Owned Mini Grids Have Become Small Power Producers</td>
<td>40</td>
</tr>
<tr>
<td>5.3 Cambodia Bucked the Trend by Embracing the Transition from Mini Grid to Small Power Distributor</td>
<td>41</td>
</tr>
<tr>
<td>5.4 Anti-Corruption and Investment Policies and Laws Thwart Interconnection</td>
<td>41</td>
</tr>
<tr>
<td>5.5 Mini Grid Technology, Scale, and History Affect Interconnection Outcomes</td>
<td>42</td>
</tr>
<tr>
<td>5.6 The Cost of Interconnection Depends on the Post-Connection Business Model</td>
<td>43</td>
</tr>
<tr>
<td>5.7 Subsidies Are Needed to Cover Revenue Shortfalls</td>
<td>45</td>
</tr>
<tr>
<td>5.8 Mini Grids versus the Main Grid: A False Dichotomy?</td>
<td>47</td>
</tr>
<tr>
<td>5.9 Why Do Consumers Sometimes Choose the Higher-Priced Electricity Supplier?</td>
<td>48</td>
</tr>
</tbody>
</table>
5.10 Invigorating Investment by Proactively Developing Regulatory Frameworks ......................... 49
5.11 Emerging Developments Affecting Mini Grids ................................................................. 50
5.12 Recommendations ........................................................................................................... 53

APPENDIX Technical Primer on Main Grid–Connected Mini Grids ........................................ 57

LIST OF FIGURES AND TABLES
Map 2.1 Electricity Licensees in Battambang Province, Cambodia, 2015 ..................................... 6
Figure A.1 Schematic of Mini Grid Supplying Electricity to its own Customers and Selling Excess to
the National Grid ....................................................................................................................... 59

Table 2.1 Standardized Tariffs Charged by Distribution Franchisees that Purchase Wholesale
Electricity from the National Grid ................................................................................................. 8
Table 2.2 Example of Typical Distribution Franchisee with Calculated Full Cost–Recovery Tariff .... 9
Table 4.1 Donor Programs for Scaling Micro-Hydropower in Indonesia ...................................... 26
Table 4.2 Policies that Apply to Independent Power Producers of Renewable Energy in Indonesia .. 29
Table 4.3 Grid-Interconnected Mini Grid Projects in Indonesia that Started as Stand-Alone Projects, 1991–2006 ....................................................................................................................... 35
Table 4.4 Grid-Interconnected Mini Grid Projects in Indonesia that Started as Stand-Alone Projects, 2008–13 ....................................................................................................................... 36
Table 5.1 Equipment Requirements of Post-Interconnection Business Models ......................... 44
Of the 1.1 billion people in the world currently without access to grid electricity, an estimated 400 million people could be connected at lower cost by mini grids, according to the International Energy Agency (IEA). In Sub-Saharan Africa alone, 140 million people will be connected to mini grids in a business-as-usual scenario, requiring the development of 100,000–200,000 new mini grids. Significant scale-up of private sector investment will be needed if these targets are to be met.

Over the past four years, the World Bank has approved more than $300 million for investments in mini grids in 17 countries, focusing particularly on catalyzing private sector. The Energy Sector Management Assistance Program (ESMAP) has also provided direct and indirect technical support of mini grids in both Asia and Africa through the Global Facility on Mini Grids (GFMG).

Experience has shown that significant private investment will not be forthcoming if a country’s policy and regulatory rules of the game are unclear or overly burdensome. Of all the rules and policies that can affect private investment in isolated rural mini grids, the one potential private investors cite most frequently concerns what happens to their operations after the main grid arrives.

Regulators in a number of countries are already addressing this concern. Nigeria, Rwanda, and Tanzania have all issued rules or regulations that offer several post-interconnection business options for developers of isolated mini grids. These regulations typically state that after the main grid arrives, a previously isolated mini grid has the right to become a small power distributor, a small power producer that sells exclusively to the national grid, or some combination of the two. The regulations also specify compensation rules or principles for deciding how much mini grid developers should be paid for some or all of their distribution and generation assets if they want to exit the mini grid business at a particular location.

It remains to be seen whether these regulatory rules will be implemented or exist only as pretty words in government gazettes. The authors of this book shed light on this key issue by examining the real-world experiences of isolated mini grids that were connected (or not connected) to the main grid in three Asian countries. Their detailed case studies describe the regulatory, financial, and engineering experience of mini grids in Sri Lanka, Cambodia, and Indonesia when the main grid reached villages. Most important, the case studies go beyond simply describing what happened when the big grid arrived. They also offer plausible explanations as to why it happened.

One must always be careful in generalizing from a few specific cases. The authors make some specific recommendations about both the regulatory and technical requirements needed to achieve a more seamless interconnection of community and privately owned mini grids using these technologies in the future, but they caution against generalizing too much from the experiences of three countries.

Two of the cases, Sri Lanka and Indonesia, are similar in that the mini grids are hydropower based and operated by community organizations. They are also similar in another respect: When the main
grid of the government-owned utility arrived in their villages, most (though not all) of these mini grids went out of existence, and the communities’ investments in both generation plants and distribution facilities were generally lost. This is unfortunate. These community-owned organizations had provided a genuine service. Before the grid arrived, they provided grid-quality electricity in remote villages in which private investors would probably not have been willing to invest. The authors make some useful recommendations on how it might be possible to achieve a different post-interconnection outcome in the future through possible joint ventures with private operators.

The other case in the book, Cambodia, is remarkable. Cambodia’s regulatory and subsidy policies made possible a major transformation in which hundreds of privately owned diesel mini grids were able to convert from isolated mini grids to connected small power distributors that offer connection to the national grid. Since conversion, the private operators have been able to provide their customers with more hours of service, at significantly lower prices.

Mini grids are not a new phenomenon. More than 100 years ago, they were the starting point for electrification in many countries, including China, Sweden, the United Kingdom, and the United States. In the early stages of electrification, when there was no central grid in these countries, mini grids were often the building blocks for what later became the interconnected central or main grid. These early mini grids can be thought of as the first generation of mini grids. As the main grid spread, mini grids were either integrated into the main grid or went out of existence. They mini grids faced many of the regulatory and organizational issues faced by mini grids in developing countries in Africa and Asia today.

Second-generation mini grids—the subject of this book—are found mostly in low-income countries. Unlike the earlier mini grids, these mini grids are built to fill the empty, mostly rural spaces that have not yet been reached by the main grid or where it would be too costly to extend the main grid. These mini grids have typically been built and operated by local communities and local entrepreneurs. When the main grid reaches them, they usually go out of existence or transform themselves into small power producers (if using a renewable energy rather than diesel) or become small power distributors.

Over the past few years, a third-generation of mini grid technologies and business models has emerged. These third-generation mini grids differ from the second-generation mini grids in several ways:

1. National and international private companies, as opposed to local entrepreneurs or community organizations, are building or proposing to build these third-generation projects.
2. Technological developments have allowed third-generation projects to use more modular technologies (especially solar photovoltaic generation backed up with diesel, batteries, or both) and state-of-the-art hydropower with sophisticated pay-as-you-go billing and real-time Internet-based monitoring systems.
3. Mini grids are no longer being built only in isolated rural villages. In the Indian state of Uttar Pradesh, for example, one private mini grid operator (OMC Power) has built many mini grids in villages that are already served by a government-owned distribution utility, because the distribution utility has been unable to provide reliable service, especially during peak evening
hours. A similar arrangement has been proposed in the mini grid regulations recently issued by the Nigerian electricity regulator.

4. In Kenya and elsewhere, public-private partnerships have proposed building and operating mini grids instead of pure publicly owned or pure privately owned mini grid systems. These partnerships are motivated, in part, by the reality that it is politically easier to channel a subsidy through a government entity in a joint venture than to openly give the same or even a smaller subsidy to a private company.

To better understand these emerging developments, the report recommends some areas for further research as well as possible pilots that could yield information on different second-generation business models and the associated technical requirements.

This book is an example of how the GFMG takes practical knowledge gained at the national level and elevates it to the global level to inform policy and strategy for governments, the private sector, and development partners. The Facility is based on two pillars. Under its first pillar, the GFMG provides on-the-ground technical assistance and project planning support (such as business plans, geospatial planning, and regulatory and policy advice) to developers, government officials, investors, and World Bank operations teams in more than 20 countries. Under the second pillar, the GFMG takes the practical knowledge gained in the first pillar and disseminates the knowledge as quickly as possible—in notes, reports, books and workshops—reflecting ESMAP’s philosophy that it is important to acquire practical ground-level information and to disseminate it quickly. High-level debates over broad strategy will continue. But ESMAP believes that it can make its greatest contribution to mini grid development by providing practitioners with knowledge they can act on to successfully implement high-level strategies.

Rohit Khanna
Program Manager
Energy Sector Management Assistance Program
December 2017
This study is based on several dozen in-person and telephone interviews and email exchanges with private sector developers, regulatory staff, other government officials, and representatives of nongovernmental organizations. We thank all of the many people who gave hours of their time to answer our questions. This study would not have been possible without their generous cooperation and insights.

We owe a special debt of gratitude to Jon Exel, the team leader for ESMAP’s Global Facility on Mini Grids (GFMG). Back in 2016, he urged us to take a look at some real-world examples of what happens “when the big grid connects to the little grid.” It soon became clear that the experiences of Sri Lanka, Cambodia, and Indonesia merited closer examination. None of us realized how long it would take to track down the facts and then decide what the facts meant for policy and regulation. Jon was very patient with our efforts to dig deep. We could not have asked for a better team leader.

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### ABBREVIATIONS

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Full Form</th>
</tr>
</thead>
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<tr>
<td>CEB</td>
<td>Ceylon Electricity Board</td>
</tr>
<tr>
<td>CREE</td>
<td>Community Rural Electrification Entity</td>
</tr>
<tr>
<td>DFCC</td>
<td>Development Finance Corporation of Ceylon</td>
</tr>
<tr>
<td>EAC</td>
<td>Electricity Authority of Cambodia</td>
</tr>
<tr>
<td>EdC</td>
<td>Electricité du Cambodge</td>
</tr>
<tr>
<td>ESD</td>
<td>Energy Services Delivery</td>
</tr>
<tr>
<td>FECS</td>
<td>Federation of Electricity Consumer Societies</td>
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<tr>
<td>GFMG</td>
<td>Global Facility on Mini Grids</td>
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<tr>
<td>IEA</td>
<td>International Energy Agency</td>
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<tr>
<td>MHP</td>
<td>micro-hydropower</td>
</tr>
<tr>
<td>NEA</td>
<td>Nepal Electricity Authority</td>
</tr>
<tr>
<td>NGO</td>
<td>nongovernmental organization</td>
</tr>
<tr>
<td>PLN</td>
<td>Perusahaan Listrik Negara</td>
</tr>
<tr>
<td>PPP</td>
<td>public-private partnership</td>
</tr>
<tr>
<td>PUCSL</td>
<td>Public Utilities Commission of Sri Lanka</td>
</tr>
<tr>
<td>REF</td>
<td>Rural Electrification Fund</td>
</tr>
<tr>
<td>RERED</td>
<td>Rural Energy for Rural Economic Development</td>
</tr>
<tr>
<td>Rp</td>
<td>Indonesian rupiah</td>
</tr>
<tr>
<td>SEA</td>
<td>Sustainable Energy Authority</td>
</tr>
<tr>
<td>SPD</td>
<td>small power distributor</td>
</tr>
<tr>
<td>SPP</td>
<td>small power producer</td>
</tr>
<tr>
<td>SPPA</td>
<td>standardized power purchase agreement</td>
</tr>
<tr>
<td>UNDP</td>
<td>United Nations Development Programme</td>
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<tr>
<td>VECS</td>
<td>Village Electricity Consumer Societies</td>
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<td>VHP</td>
<td>village hydro projects</td>
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<tr>
<td>VHS</td>
<td>village hydro system</td>
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</tbody>
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All currency is in United States dollars ($) unless otherwise indicated.
EXECUTIVE SUMMARY

Most mini grids in developing countries begin life as isolated electrical systems that are not connected to a country’s main grid. They are built because expansion of the national or main grid has been slow and unpredictable in rural areas. In the words of one villager in Tanzania served by a mini grid, “We got tired of waiting.”

In recent years, the main grid has been extended in many African, Asian, and Latin American countries. Its expansion raises a critical question: What happens to the mini grid when the main grid arrives?

This study attempts to answer this question, using the recent (and ongoing) experiences of Cambodia, Sri Lanka, and Indonesia. The three case studies follow a similar structure. Each describes the regulatory, commercial, and technical characteristics before and after the main grid arrived in villages that had previously been served by isolated mini grids.

Regulators and policy makers in a growing number of countries—including Cambodia, India, Indonesia, Nepal, Nigeria, Rwanda, Sri Lanka, and Tanzania—have issued or proposed rules or regulations that specify business options for previously isolated mini grids. The five most common options specified include the following:

1. **Compensation and exit**: The mini grid goes out of business, and the developer receives some compensation for assets taken over by the main grid operator (typically a government-owned national utility).

2. **Small power purchaser (SPP)**: The mini grid converts to a main grid–connected SPP and no longer sells at retail to villagers.

3. **Retail + SPP**: The mini grid continues to sell electricity to its retail customers with its own generated electricity or wholesale purchases from the main grid operator and also sells electricity to the main grid operator when a surplus is available.

4. **Small power distributor (SPD)**: The mini grid converts to an SPD that buys its full supply at wholesale from the main grid and sells its purchased electricity to villagers at retail (with or without back-up generation).

5. **Side-by-side but not interconnected**: The mini grid continues to serve customers even when the grid arrives, with no electrical interconnection between it and the main grid, even though both operate in the same village.

The first option is the going out of business option. The other four are co-existence options. A sixth outcome has also been observed:

6. **Abandonment**: The mini grid is forced to abandon its generation and distribution equipment.

Abandonment has been the dominant outcome for the community-owned hydro-powered mini grids in Sri Lanka and Indonesia. The case studies explain why abandonment has been so prevalent in these countries.
CAMBODIA

What Happened?

Cambodia’s isolated mini grids were typically diesel-fired systems built and operated by local entrepreneurs. They filled an electricity supply vacuum that existed because the main grid did not reach many rural villages during and following the country’s turmoil in the 1970s through the early 1990s. The isolated mini grids were a spontaneous bottom-up initiative of village-level entrepreneurs, without the support of a government program.

In the early 2000s, a major transformation occurred. The transmission and medium-voltage networks of the national utility, Electricité du Cambodge (EdC), began to expand more rapidly into rural areas. When this happened, most isolated mini grids became SPDs that purchased electricity at wholesale from EdC or neighboring countries. Currently, more than 250 formerly isolated private mini grids have connected to the national grid as SPDs, serving more than a million customers.

This shift to SPDs accelerated after 2006, when a national electricity regulator, the Electricity Authority of Cambodia (EAC), came into existence. To increase the deployment of electricity, increase electricity quality, and reduce high retail tariffs from diesel mini grid levels ($0.40–$1 per kWh), the EAC put in place a comprehensive program that granted long-term distribution licenses to private sector franchisees that invested in utility-quality distribution networks and extended their networks throughout prescribed service territories.

Before 2016, each SPD charged its own individually calculated cost-reflective tariff. In early 2016, the government announced that the retail tariffs charged by privately owned SPDs would be uniform throughout the country. At the same time, it committed to providing SPDs with an ongoing operational subsidy. The subsidy, calculated annually by the EAC for each SPD, was designed to close the gap between the mandated standardized retail tariffs and each SPD’s actual higher costs. It is paid from a Rural Electrification Fund capitalized by EdC.

Why?

Cambodia’s experience with mini grids is unique: No other country appears to have converted so many previously isolated mini grids into connected SPDs. Its success reflects several factors:

- The regulator used the “stick” of its licensing authority to induce private mini grid operators to invest money to improve their distribution systems so that they could operate as SPDs once connected to the EdC grid.
- EdC viewed the mini grids and later the SPDs as good for its own commercial viability.
- The national government provided a “carrot” of operational subsidies to the SPDs, which were required to support a uniform retail tariff that did not recover their actual costs.
- The distribution margin is wide enough for a well-run mini grid to be commercially viable as a connected SPD.
- Over time, the SPDs have grown and can spread their fixed costs over more customers and over more kWh sales.
Mini grid owners were motivated to operate efficiently and expand into neighboring villages to achieve economies of scale.

**Sri Lanka**

**What Happened?**

Between 1997 and 2012, more than 250 isolated community-owned micro-hydropower projects came into existence in Sri Lanka, with financial support from the government and the World Bank. The top-down program was designed to create village-level mini grids that would be owned and operated by community organizations known as Village Electricity Consumer Societies (VECS). The VECS received assistance from private consultants, who were given bonus payments for each mini grid they helped create that was still operating after six months. Motivated by the payments, the consultants helped identify viable hydropower sites and then convinced households in villages to develop the project. Once the projects were built, the consultants continued working with the VECS to ensure that the projects were operating as intended (at least through the initial six-month period).

These projects were small, with a median size of 27 customers and an average installed capacity of 7.5 kW (World Bank 2012). At their peak, the VECS served about 10,000 rural households, with combined installed capacity of about 4 MW.

With the arrival of the main grid of the national utility (the Ceylon Electricity Board [CEB]), more than 100 of the isolated mini grids went out of existence. Only three VECS converted their mini grids into main grid–connected SPPs. As SPPs, they sell wholesale electricity to the national utility but no longer provide retail service to village households, as most households opted to become retail customers of the CEB.

The conversion to an SPP required investments in interconnection equipment and payments for government approvals. In addition, the VECS, which were consumer welfare societies, had to be reconstituted as limited liability companies in order to be able to sign the standardized power purchase agreement with the CEB.

The Energy Forum, a Sri Lankan NGO, played a lead role in facilitating the conversion of the three VECS. It and another NGO, the Federation of Electricity Consumer Societies, hold ownership shares in the new limited liability companies. The Energy Forum estimates that more than 50 other abandoned mini grids owned by VECS could convert to SPPs if financing could be obtained.

**Why?**

Most VECS went out of existence when the CEB grid reached the villages they served. They did so for several reasons:

- The CEB offered lower (highly subsidized) tariffs and a higher tier of service (more hours of service and generally without limitations on the size of appliances that can be connected).
With a median size of 27 customers, the VECS were too small to survive as commercially viable SPDs.

To save money, the VECS distribution facilities had not been built to meet CEB standards.

The VECS did not have access to any ready sources of financing that would have allowed them to finance the cost of interconnection equipment and expansion of their generation capacity.

The regulatory requirements to obtain SPP status had been designed for larger generators and were too costly for the smaller generators operated by VECS.

VECS were widely viewed as a transitional arrangement that were designed to provide a basic level of grid electricity until the CEB arrived with better service at a lower price.

**INDONESIA**

**What Happened?**

Micro-hydropower projects in Indonesia have benefitted from decades of local capacity building by the government and international donors. Since the 1990s, more than 1,300 projects have been built, of which 1,033 received funding support from the government.

In mini grid–powered villages where the main grid arrived, the transition from isolated to grid-connected mini grids has been a challenge—but not an impossible one. Nine formerly isolated mini grids connected to the main grid, selling electricity at wholesale to the national utility (Perusahaan Listrik Negara [PLN]) under government-specified feed-in tariffs. The additional income generated from wholesale SPP sales to PLN has helped improve the commercial sustainability of the mini grid operations and finance social improvement projects within the village.

In another 150 villages, the communities abandoned their mini grids, and most households became PLN retail customers. In 40–50 villages, community-owned mini grids continue to sell electricity on the mini grids’ distribution systems, which remains physically separate from the PLN system. These mini grids appear to have survived because their tariffs are lower than the tariffs charged by PLN or because many rural households were unwilling or unable to pay the high fees required to connect to the main grid.

**Why?**

Most village projects were abandoned when the national grid arrived. But an important precedent was set in two important connection modalities: (i) five projects connecting as SPPs and selling electricity to the national grid (the SPP option) and (ii) four projects continuing to sell electricity to retail customers and interconnecting as SPPs to sell excess electricity to the national grid (the retail + SPP option). These nine mini grids have pioneered the regulatory environment and technical procedures; others may be able to follow in their footsteps.

Just 6 percent of the mini grids in Indonesia remained in business after the main grid arrive. Two main reasons explain the low rate of interconnections:
Until very recently, Indonesian Law did not allow government-funded micro-hydropower projects to connect. Because the vast majority of projects received government funding, the pool of legally connectable projects was very small. Laws designating what could be done with government-funded infrastructure were interpreted to mean that government-funded infrastructure cannot be used for private income generation. In May 2017, the government changed the regulation, issuing a decree that explicitly allows the grid connection of government-funded micro-hydropower projects.

Tariffs for grid-connected micro-hydropower projects have been low ($0.03–$0.04 per kWh). A decree issued in 2017 specifies a 20-year power purchase agreement at tariffs of about $0.37 per kWh for micro-hydropower.

**CONCLUDING OBSERVATIONS**

Isolated hydro-powered mini grid were the “first responders” in many villages in Sri Lanka and Indonesia (as well as in Malaysia, Nepal, the Philippines, Tanzania, Thailand, and parts of India). They brought near grid quality AC electricity to communities that were not served by the national utility and or considered commercially unviable by private investors. They filled a critical void by providing isolated villagers with (albeit generally limited amounts of) electricity many years before other supply options became available.

Few of these projects have connected with the national grid. The ones that have appear to be viable, generally with some financial and technical assistance from NGOs to help with the transition. More conversion from isolated mini grids to connected SPPs may be possible—if some hurdles are overcome:

- Utilities are generally not enthusiastic about interconnecting small distributed generation, because the transaction costs are high. These costs include the regulatory tasks involved in designing standardized power purchase agreements, the procedural tasks involved in paying small invoices for relatively small amounts of money, the need to conduct studies to review the engineering implications of the interconnection, and sometimes the need to make adjustments to their own operational practices to ensure that their network remains safe and stable when receiving electricity from small isolated generators. It is not surprising that most utilities that have connected to SPPs have been forced to do so by governments or regulatory authorities that see the overall benefit to the country.

- The tariffs utilities are willing to pay for generated wholesale electricity from these projects are often low.

- Interconnection of generation to the main grid involves injecting electricity back into the main grid, which is more difficult than interconnecting a distribution network that draws electricity only from the grid. Connecting as a SPP requires synchronizing generation to the national grid and calibrating a variety of safety relays. In Indonesia, the cost of equipment necessary for grid synchronization—just one component of the interconnection cost—is about $6,000.

- Interconnection of generation to the national grid encountered legal hurdles in both Indonesia and Sri Lanka. It takes time to resolve these hurdles, especially if they are embedded in national laws.
• Changes in the business models and legal structures of local village cooperative or VECS are needed before they can sell electricity under contract to the national utility or obtain loans from commercial banks.

Other hurdles exist for community-owned mini grids that wish to become SPDs. Three factors have prevented isolated micro-hydropower mini grids in Indonesia and Sri Lanka from becoming SPDs:

• The mini grids’ distribution networks were often not built to the standards that utilities require for distribution networks.

• The entities lacked the legal permission to purchase and resell electricity from the national grid.

• Once connected to the national utility’s main grid, village customers expect them to charge the same subsidized retail tariffs charged by the national utility. Unless their bulk supply price is subsidized, it is unlikely that the difference between the average bulk supply price and the average retail price would be large enough to cover their distribution margin.

In addition to these business model–specific issues, community-scale micro-hydropower mini grids encountered other barriers:

• **Scale issues**: Projects in Sri Lanka had a median capacity of 7.5 kW. The revenues from projects this small are generally inadequate to cover the full costs of operation.

• **Inability to get loans**: Commercial banks are not used to providing loans for village SPPs and have difficulty evaluating risks for these types of projects. Villagers generally lack collateral, and banks are generally not willing to accept the equipment as collateral, because it is site specific, heavy, and often encased in concrete. The difficulty in obtaining loans is compounded by the fact that community-managed mini grids charge tariffs that are too low, leaving little or no cash reserves to make repairs or to serve as equity contributions to finance the physical investments needed to construct a grid interconnection of any form. It might be easier for community micro-hydropower mini grids to get loans if they could form joint ventures with more experienced private hydropower operators. But such joint ventures have been discouraged or prohibited by national laws and policies.

Cambodia’s diesel mini grids have had remarkable success in transitioning to SPDs. Indeed, more than 200 previously isolated mini grids have made this transition. This transition has been easier technically, financially, and institutionally than the transition to SPPs, for several reasons:

• **Utilities are less averse to selling electricity than buying it from small customers.** Selling electricity to an SPD fits their business model; SPDs are yet another customer that takes electricity and sends them money. Working through SPDs means that the utility does not have to deal with directly supplying hundreds of small customers in relatively small rural locations.

• **Technical interconnection as an SPD is very easy—**all that is needed is a meter and (sometimes) a transformer. None of the relays required for synchronization and safe operating of parallel generation are required.
There is little change in business models. Diesel mini grid operators in Cambodia earned revenues by selling electricity to retail end-use customers. After transitioning to SPDs, the operators still earned revenues by selling electricity to retail end-use customers.

Additional conditions in Cambodia enabled the mass transition by mini grids to SPDs. They may not exist or be replicable in other countries:

- The high cost of diesel electricity (as high as $1 per kWh) created a class of customers that was willing to pay $0.20 per kWh or more for electricity. Moreover, EdC’s rural tariffs were roughly the same as the mini grid tariffs, providing distribution margins that allowed SPDs to be commercially viable.
- Labor costs in Cambodia are low. Licensing and tariff regulation of hundreds of separate SPDs is therefore less financially burdensome than it might be in countries with higher labor costs.
- The private owners of the mini grids were entrepreneurial. They sought out new customers, pursued opportunities to expand average consumption levels, and actively sought opportunities to buy out neighboring mini grids to achieve economies of scale.
- The Electricity Authority of Cambodia worked very hard to ensure that isolated mini grids made investments, usually financed by family and friends, to bring their distribution networks up to the standards of the national utility.
- When the government of Cambodia ordered small distribution systems to charge uniform, non-cost-recovering retail tariffs, the government was willing and able to provide operational subsidies to meet the revenue shortfall.

GRID INTERCONNECTIONS: A POSSIBLE NEW REGULATORY APPROACH?

When communities in Indonesia and Sri Lanka and local private developers in Cambodia made their investments in isolated mini grids, no specific rules or policies were in place to inform them about their options when the main grid reached their villages. This absence of any clear government guidance probably did not matter very much for these mini grids, because their developers generally recognized that they were providing an interim electricity service until the day when the main grid arrived.

The arrival of the main grid meant lower prices and fewer restrictions on the appliances villagers could use. In the case of the local private developers in Cambodia, the regulator’s early decision to issue pure distribution licenses to replace the initial combined generation and distribution licenses ensured a relatively smooth transition to SPDs for the previously isolated mini grids.

This approach of creating policies and regulations as the need arises is not likely to work for governments in Africa and Asia that are serious about encouraging private investors to build hundreds and thousands of new mini grids. Private investors, especially large national and international companies, will not be willing to make major investments in mini grids if there is no policy and regulatory clarity as to what their post-interconnection business options will be; without
more certainty, private investment will be too risky. The cost of continuing regulatory and policy uncertainty will be the loss of major private investments that could otherwise lead to a significant scale-up of grid quality electricity in rural communities.

Fortunately, some recent developments suggest an alternative approach. In several countries (Haiti, India, Kenya, Madagascar, and Zambia), there is growing interest in—and in some instances specific proposals to create—various types of public-private partnerships (PPP) to facilitate private investments in mini grids on a larger scale. One advantage of these proposed arrangements is that the regulatory and policy decisions governing post-interconnection business options can be spelled out in the detailed provisions of the PPP contract. This “regulation by contract” (described in section 5.10) is an alternative to traditional regulation, which relies on case-by-case application of general principles or standards in mini grid rules or laws. In the late 1990s and early 2000s, it was successfully used in a number of privatizations of distribution enterprises (see Bakovic, Tenenbaum, and Woolf 2003). A similar approach applied to PPPs to promote investments in new mini grids could also be successful.

RECOMMENDATIONS

Several recommendations emerge from the successes and failures documented in the case study countries.

- Create a regulatory and policy framework that allows for mini grids to operate as stand-alone systems and integrate with the national grid. Such a framework would reduce the commercial risk that mini grid developers face in building isolated systems. The existence of a regulatory roadmap that details all business options available to the mini grid developer when the main grid eventually arrives would facilitate electrification of areas far from the grid using mini grids.

- Offer a range of post-interconnection business options for what happens “when the big grid reaches the little grid.” They should include continuing business as SPPs, becoming SPDs, and buying electricity from and selling it to the main grid operator and other entities connected to the main grid.

- Streamline regulatory processes so that licensing, permission to interconnect to the main grid operator, and other business and environmental approvals are integrated and duplication of bureaucratic processes minimized.

- Offer umbrella licenses, permits, and registrations for mini grid developers that use the same generating and distribution technologies at multiple sites.

- Specify the conditions under which mini grids should be built to grid-ready standards and the conditions under which less costly “skinny-grids” should be allowed.

- Create rules that specify how mini grid developers will be compensated for their assets in the event that the main grid arrives and the mini grid operator shuts down. Consider whether the mini grid operator’s work in “pre-electrifying” the area merits compensation.

- Eliminate prohibitions that prevent mini grids originally built as government-funded isolated projects from connecting to the main grid, possibly by allowing government contributions to
the original isolated mini grid assets to be repaid over time using a portion of revenues from electricity sales to the main grid.

- Remove legal and regulatory barriers that prevent communities from entering into joint ventures with private developers for new or expanded mini grids, whether isolated from or connected to the main grid.

- Create subsidy parity. If capital and operating subsidies are currently provided to the main grid owner for grid extension and for operating mini grids, provide comparable subsidies to private mini grid operators operating in joint ventures or independently.

REFERENCES


INTRODUCTION

Most mini grids\(^1\) in developing countries begin life as isolated electrical systems that are not connected to the country’s main grid.\(^2\) They arise because expansion of the main grid has been slow and unpredictable. In the words of one villager in Tanzania served by a mini grid: “We got tired of waiting.”

In recent years, the main grid has expanded to reach more rural areas in many African, Asian, and Latin American countries. What happens to existing mini grids when the main grid arrives? This study attempts to answer this question by studying the experiences of three Asian countries: Cambodia, Indonesia, and Sri Lanka.

1.1 COUNTRY OVERVIEWS

Cambodia

In Cambodia, local entrepreneurs built and operated isolated mini grids, typically fired by diesel. They filled a vacuum that existed because the main grid did not reach many rural villages during and following the country’s turmoil in the 1970s through the early 1990s.

In the early 2000s, as the main grid expanded more rapidly into rural areas, more than 250 previously isolated mini grids became small power distributors (SPDs). The SPDs purchase electricity at wholesale, either from the national utility (Electricité du Cambodge \([EdC]\)) or from neighboring countries.

To increase the deployment of electricity, improve quality, and reduce high retail tariffs from diesel mini grid levels (\(\$0.4–\$1.0\) per kWh), the Electricity Authority of Cambodia (EAC) put in place a comprehensive program that grants long-term distribution licenses to private sector franchisees that invest in utility-quality distribution networks and extend their networks throughout prescribed service territories. In 2016 retail tariffs to end-users on these rural distribution systems were standardized and subsidized, with the gap between retail tariffs and a project-specific cost recovery tariffs paid out of a Rural Electrification Fund capitalized by EdC. The program has been successful. In 2005 the isolated mini grids served fewer than 100,000 customers. With the widespread conversion to SPDs, the SPDs and the remaining isolated mini grids served more than 1 million customers in 2015.

Sri Lanka

Between 1997 and 2012, more than 250 isolated hydro-powered mini grid projects owned by community organizations known as Village Electricity Consumer Societies VECS came into existence in Sri Lanka, with financial support from the government and the World Bank. The VECS received considerable assistance from private consultants, who were given bonus payments for each mini grid they helped create that was still operating after six months.
When the national utility’s main grid reached these villages, more than 100 of the isolated mini grids were abandoned. The national utility, the Ceylon Electricity Board (CEB), became the new electricity supplier to most VECS members.

Only three community-owned mini grids succeeded in converting to grid-connected small power producers (SPPs). In all three instances, there was heavy technical support from two nongovernmental organizations (NGOs). Since the conversion, these three mini grids no longer provide retail service to their members. Their sole source of revenue comes from wholesale sales of electricity to the CEB.

**Indonesia**

Micro-hydropower projects in Indonesia have benefitted from decades of local capacity building by the government and international donors. Since the 1990s, more than 1,300 projects have been built, of which 1,033 received funding support from the government.

Nine formerly isolated micro-hydropower mini grids have connected to the national utility (Perusahaan Listrik Negara [PLN]) grid, selling electricity at wholesale to PLN under government specified feed-in tariffs. The income generated from these sales has helped increase the commercial sustainability of the mini grid operations and improved social conditions in the village.

In another 150 cases, communities abandoned their mini grids after the main grid arrived, and most of the community became PLN retail customers. In 40–50 villages, the community-owned mini grids continue to sell electricity on the mini grids’ existing distribution systems, which remain physically separate from the PLN distribution system. These mini grids appear to have survived because they charged retail tariffs that are lower than the tariffs charged by PLN on these islands or because rural households were unwilling or unable to pay the high fees required by PLN to connect to the PLN grid.

### 1.2 Options for Previously Isolated Mini-Grids

Regulators and policy makers in a growing number of countries—including Cambodia, India, Indonesia, Nepal, Nigeria, Rwanda, Sri Lanka, and Tanzania—have issued or proposed rules or regulations that specify business options for previously isolated mini grids. The five most common options specified include the following:

1. **Compensation and exit**: The mini grid goes out of business, and the developer receives some compensation for assets taken over by the main grid operator (typically a government owned national utility).

2. **Small power purchaser (SPP)**: The mini grid converts to a main grid–connected SPP and no longer sells at retail to villagers.

3. **Retail + SPP**: The mini grid continues to sell electricity to its retail customers with its own generated electricity or wholesale purchases from the main grid operator and also sells electricity to the main grid operator when a surplus is available.
4. **Small power distributor (SPD):** The mini grid converts to an SPD that buys its full supply at wholesale from the main grid and sells its purchased electricity to villagers at retail (with or without back-up generation).

5. **Side-by-side but not interconnected:** The mini grid continues to serve customers as usual even when the grid arrives, with no electrical interconnection between it and the main grid, even though both are operating in the same village.

The first option is the going out of business option. The other four are co-existence options. A sixth outcome has also been observed:

6. **Abandonment:** The mini grid abandons its generation and distribution equipment without any compensation.

Abandonment has been the dominant outcome for the community-owned hydro-powered mini grids in Sri Lanka and Indonesia. The case studies explain why abandonment of mini grids has been so prevalent in these countries.

### 1.3 Scope of This Study

The three country case studies follow a similar structure. Each describes the regulatory, commercial, and technical characteristics before and after the main grid arrived in villages that had previously been served by the isolated mini grids. The studies describe real-world experiences for the SPP option, the SPD option, and the retail + SPP option for two generating technologies (mini-hydropower and diesel). They do not provide examples of the “compensation and exit” post-interconnection business outcome or other generating technologies (solar, biomass, hybrids). Such an effort would require additional case studies. It will be especially important to examine the post-connection options for solar-hybrid mini grids, which are emerging as the dominant technology choice throughout Sub-Saharan African and in at least two countries in Asia (Bangladesh and India).

In two of the case-study countries (Indonesia and Sri Lanka), the isolated mini grids were owned by community organizations. It is possible that the post-interconnection outcomes would have been different if the isolated mini grids had been built and operated by private entities.

The experiences of these three countries revealed an important lesson: The issuance of regulatory rules and policy pronouncements does not guarantee that the options they specify will be of practical interest to mini grid developers. Good intentions of government officials do not translate into on-the-ground results if the economics of an option are not viable. At the end of the day, it is the underlying economics that determine whether a rule or policy is workable.
More than 250 formerly isolated private sector mini grids have connected to the national grid as small power distributors (SPDs), known in Cambodia as “distribution licensees.” They purchase electricity at wholesale from the national utility, Electricité du Cambodge (EdC), and resell it at retail to households and businesses.

Before the arrival of the national grid, these rural mini grids used diesel generators. Tariffs varied depending on the size of the mini grid and (especially) the price of diesel fuel. They ranged from CR 1600 ($0.4) to CR 4,100 ($1) per kWh.\(^3\)

Retail tariffs for these new distribution franchisees are now standardized across the country at CR 480 ($0.12) or CR 800 ($0.2) per kWh, depending on the customer type. A government-mandated subsidy scheme helps cover the gap between these standardized tariffs and the SPD’s full costs (power purchase plus distribution costs).

The conversion from isolated diesel fired mini grids to main grid-connected SPDs has led to increases in the number of customers served and improvements in the quality of supply. The number of customers served by these small private electricity systems rose from fewer than 100,000 in 2005 to more than 1 million in 2015. Between 2003 and 2015, the number of licensees providing less than 24 hours of service decreased from 50 out of 85 (59 percent) to 5 out of 311 (less than 2 percent) (Castalia Strategic Advisors forthcoming).

2.1 POWERING HOUSEHOLDS BEFORE A VILLAGE IS CONNECTED TO THE MAIN GRID

Electrical infrastructure in Cambodia was damaged and neglected during the violence and chaos of the 1970s and 1980s. Reconstruction restarted in the 1990s.

Electricity in the capital city of Phnom Penh and large towns was historically under government ownership and control—generally by EdC, sometimes by provincial governments. EdC also supplied electricity to customers in about a dozen areas near Vietnam with bulk electricity it purchased from Vietnam. In border areas near Vietnam, Thailand, and the Lao People’s Democratic Republic, private entrepreneurs purchased electricity at bulk from neighboring countries for resale to retail customers on small privately owned and operated distribution systems.

Outside major towns and border areas, rural electricity supply was rare. Where it existed in the 1990s, it was in private hands. Local entrepreneurs set up diesel generators that produced 24–1,520 kW; most mini grids generated less than 200 kW. They began by supplying electricity to a few neighbor households, expanding little by little as finances permitted.
There is no firm figure on the number of these rural electricity enterprises. A World Bank–commissioned study conducted in 2001 by Enterprise Development Cambodia developed a list of 218, including enterprises registered with the government and informal mini grids encountered while conducting field visits in 15 of Cambodia’s 24 provinces. Most of them supplied electricity for a few hours each evening; some provided power in the morning and the evening. These diesel mini grids typically provided electricity at a Tier 2 level on the World Bank’s Multi-Tier Framework. Typical payments in 2001 ranged from $4.40 to $12 a month (Meritec Limited 2001).

Some systems had transformers and medium voltage (22 kV) lines, but most were low-voltage (230/380 V) only, limiting both the maximum electrical load and the distance across which distribution lines could be extended. Electricity supply in these private mini grids was generally not very stable. Most generators were purchased second-hand, and distribution wiring networks were often undersized and not built to standards of any kind. Distribution systems were generally in bad shape, with inadequate poles, undersized conductors, and poor splices.

Retail tariffs of $0.40–$1.0 per kWh were much higher than the tariffs in urban areas served by EdC, which ranged from $0.15 to $0.25 per kWh, depending on the location. From the beginning, Cambodia was thus accustomed to high tariffs and variation in tariffs both across villages and between villages on the one hand and towns and cities on the other.

### 2.2 Regulatory Framework for Isolated Mini Grids

Through the 1990s, some mini grids operated under licenses from the provincial government or the ministry. Licenses were issued sporadically, however, and some projects operated without licenses.

The Energy Authority of Cambodia (EAC) was established under Cambodia’s Electricity Law, promulgated in February 2001. From its beginnings, it adopted the goals of expanding service to more areas, improving quality, and regulating tariffs. The law required that all providers of electric power service obtain a license. Service providers were given a six-month window to apply for licenses.

Starting in February 2002, the EAC began issuing “consolidated generation and distribution licenses” to EdC and private isolated mini grids that both generated electricity and sold it to retail customers over private distribution networks. In April 2002, it issued its first distribution licenses to a distribution franchisee that purchased electricity at wholesale tariffs from EdC (all licenses are publicly available for download at the EAC website, [http://eac.gov.kh/en/license/](http://eac.gov.kh/en/license/)).

In considering the regulatory approach to use with mini grids, the EAC decided to plan for smooth integration of the mini grid with the main grid when the main grid arrived. One key aspect of this effort has been the tying of licensing approval process to improvement in mini grid distribution infrastructure so that it is grid ready. Early on the EAC issued two-year licenses to isolated mini grids, with the condition that the license would be extended as long as the infrastructure was improved and reports regularly filed. For mini grids that completed improvements to their distribution networks, the EAC issued licenses for 5–20 years.
The license granted describes a geographical service area (for an example, see map 2.1). The licensee is obligated to expand its operation to the entire licensed area throughout the duration of the license. If it fails to do so, it can lose its license, which can be given to another private company (to date the EAC has not withdrawn any licenses, as compliance with network expansion requirements has been good). In addition to the threat of license revocation, the EAC provided licensees with licenses of five years or longer with financial assistance, in the form of loan guarantees, interest-free loans, and grants through the Rural Electrification Fund’s “Program for Providing Assistance to Develop Electricity Infrastructure in Rural Areas.”

Map 2.1 Electricity Licensees in Battambang Province, Cambodia, 2015

EAC staff made frequent site visits to determine whether required improvements had been made. The transactions costs involved in this monitoring proved to be high, because of the poor state of roads and low population density (89 per square kilometer, compared with 135 in Thailand and 299 in Vietnam). To address this issue, in 2013 the EAC and the Provincial Department of Mines and Energy (PDME) reached an agreement to entrust certain monitoring duties and assistance with
dispute resolution to local PDME officers in provinces as representatives of the EAC. Licensees submitted quarterly and annual reports to the EAC using forms available on the EAC website.

These rules incentivized improvement in the quality of the distribution system in these isolated mini grids, bringing them up to sufficient technical standards to interconnect with and purchase electricity from EdC when it arrived. In all provinces, licensees have met or exceeded contracted distribution extension requirements. As of 2014, all distribution licenses had terms of five years or more.

The EAC was more than a traditional regulator. In addition to the traditional regulatory tasks of issuing licenses and setting maximum prices and minimum quality of service standards, it provided ground-level engineering assistance to many licensees. This assistance typically took the form of advice on how to build and operate the mini grid’s distribution system so that it could integrate with main grid at some time in the future.

### 2.3 WHAT HAPPENED AFTER THE MAIN GRID ARRIVED?

With the arrival of the main grid (either EdC or electricity from across the border), mini grids generally connected to the main grid and switched business models to become retail distributors of electricity purchased at wholesale. Each formerly isolated mini grid was exposed to a new set of regulatory, commercial, and technical arrangements.

Consumers saw an increase in supply availability and affordability. Diesel mini grids supplied a few hours of expensive electricity every evening; with the arrival of the main grid, electricity was supplied 24 hours a day at much lower cost. In World Bank Multitier Framework terms, service levels rose from Tier 2 to Tier 4 or 5.

#### Regulatory Aspects

*Licenses to distribution franchisees*

Distribution licenses are available for companies that wish to purchase electricity at wholesale rates from EdC for resale to retail customers. A conversion process allows mini grids that were previously isolated and generated their own electricity to retain their generator for backup power until the transition is complete. Grid-connected licensees often maintain their consolidated (generation plus distribution) license for several months and retain their generators for use during times when there is a power outage on the national grid. After some months, the EAC ensures that the consolidated license is converted to a distribution license. Once the license type is changed to distribution, the generator is generally no longer operated, because the allowable retail tariff is not sufficient to cover generator operation (as discussed below).

The EAC’s heavy workload has caused delays in changing licenses from consolidated to distribution. One indication of them is the fact that EAC staff say that 250 distribution franchisees are operating in the field whereas the EAC annual report reports that in 2014 there were 139 valid distribution licenses and 181 consolidated licenses.
Most distribution licensees purchase electricity from EdC. Some electricity is also purchased from neighboring countries. In about 50 locations, private distribution licensees in Cambodia purchase electricity from Vietnam. Near the Thai and Lao borders, private entrepreneurs purchase electricity at bulk rates from Thailand and Lao PDR for resale to retail customers. The EAC does not regulate the wholesale tariffs charged by foreign entities selling to SPDs. The wholesale tariffs charged by these foreign suppliers are generally lower than the wholesale tariffs charged by EdC to SPDs in Cambodia.

**Regulation of retail tariffs charged by licensees**

The EAC regulates retail tariffs for both distribution franchisees and isolated mini grids. It determines subsidies to distribution franchisees to reduce and standardize the tariffs they charge. The subsidy program received attention from the highest levels of Cambodia’s government. In 2015 the prime minister announced plans for the program as part of a broader strategic initiative to reduce tariffs by 2020.7

For distribution licensees connected to the national grid, the tariff retail customers pay is a standardized tariff that is the same for distribution franchisees across the country. This tariff is like a national uniform tariff that applies only to distribution licensees. The standard tariffs for different customer classes served by distribution licensees are shown in Table 2.1.

**Table 2.1 Standardized Tariffs Charged by Distribution Franchisees that Purchase Wholesale Electricity from the National Grid**

<table>
<thead>
<tr>
<th>CUSTOMER CATEGORY</th>
<th>TARIFF (PER kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Household consuming less than 10 kWh per month</td>
<td>CR 480 ($0.12)</td>
</tr>
<tr>
<td>Agricultural customer pumping water between 9 p.m. and 7 a.m.</td>
<td>CR 480 ($0.12)</td>
</tr>
<tr>
<td>Household consuming more than 10 kWh per month</td>
<td>CR 800 ($0.20)</td>
</tr>
</tbody>
</table>

Under this tariff standardization program, the difference between the standard tariff and the distribution franchisee’s calculated full cost–recovery tariffs (the tariff that would cover their full costs but which they are not allowed to charge) is made up by cross-subsidies administered by EdC through the Rural Electrification Fund (REF).8

The EAC calculates full cost–recovery tariffs based on a standardized spreadsheet for each project.9 The model used takes into account full depreciated asset bases, operations and maintenance, projected electricity sales to different customer classes (and their tariffs), and electricity purchase costs (in the case of distribution franchisee). The EAC calculates full cost–recovery tariffs that would generate an internal rate of return of 10 percent in a well-managed company. For distribution licensees, calculated full cost–recovery tariffs are typically in the range of CR 1,050–1,200 ($0.2625–$0.30) per kWh, but some smaller distribution franchisees or franchisees recently connected to the national grid have full cost–recovery tariffs as high as CR 1,700 ($0.425) per kWh.10 The EAC recalculates the full cost–recovery tariffs for each licensee annually.
To take an example of a typical distribution franchisee with a calculated full cost–recovery tariff of CR 1,100, the total REF subsidy payments it receives depends on the composition of its customers. It receives a subsidy of CR 620 ($0.155) per kWh for sales to agriculture and customers consuming less than 10 kWh per month and a subsidy of CR 300 ($0.075) per kWh for customers consuming more than 10 kWh per month (Table 2.2).

### Table 2.2 Example of Typical Distribution Franchisee with Calculated Full Cost–Recovery Tariff

<table>
<thead>
<tr>
<th>ITEM</th>
<th>AMOUNT PER kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Subsidy for electricity sold to agriculture and low-consumption customers</td>
<td></td>
</tr>
<tr>
<td>Calculated full cost recovery</td>
<td>CR 1,100 ($0.275)</td>
</tr>
<tr>
<td>Minus standardized tariff</td>
<td>CR 480 ($0.120)</td>
</tr>
<tr>
<td>Operating subsidy</td>
<td>CR 620 ($0.155)</td>
</tr>
<tr>
<td>Subsidy for electricity sold to households consuming more than 10 kWh per month</td>
<td></td>
</tr>
<tr>
<td>Calculated full cost recovery</td>
<td>CR 1,100 ($0.275)</td>
</tr>
<tr>
<td>Minus standardized tariff</td>
<td>CR 800 ($0.200)</td>
</tr>
<tr>
<td>Operating subsidy</td>
<td>CR 300 ($0.075)</td>
</tr>
</tbody>
</table>

The distribution licensee receives a 27 percent subsidy on its sales to residential customers consuming more than 10 kWh per month and a 56 percent subsidy on sales to its smaller, poorer customers. This monthly operational subsidy is in addition to any capital subsidy received by the operator.

About $30 million was allocated for this operational subsidy in EdC’s 2016 general budget—about a third of its annual profit of roughly $100 million. The remainder is spent on capital subsidies and low-interest loans and investments in medium- and high-voltage expansion. The operational subsidy benefits about 690,000 rural customers, which works out to $43 per customer per year (about $3.50 a month).¹¹ Reductions in standard tariffs are expected to be imposed every year until 2020. Increased operational subsidies will be needed in each of the next few years unless the costs of distribution licensees fall.

In the case of isolated mini grids, the REF provides no subsidies, and the operator is allowed to charge a full cost–recovery tariff. As with distribution licensees, the tariff is calculated separately for each project. The model used for the calculation takes into account the full depreciated asset base, operations and maintenance, projected electricity sales, sales volumes to different customer classes (and their tariffs), and fuel costs (based on a diesel price index mechanism). When mini grid operators make fuel purchases, they must do so from approved fuel vendors and send the EAC a copy of their fuel invoices. If fuel prices rise or fall outside a specified price band, the tariff is increased or decreased based on a formula.¹²
There is some evidence that the EAC has tightened the full cost–recovery calculation in recent years. It does not automatically accept the actual distribution line losses of each licensee. Instead, it substitutes stricter (lower) benchmarked values. It has also disallowed some capital costs from the rate base component of the calculation. Both regulatory decisions reduce the full cost–recovery numbers, which in turn lowers the operating subsidy individual licensees receive. In effect, the EAC is saying to licensees: “Your costs of production would be lower if you operated more efficiently. We will use our calculated efficient production costs in setting the amount of operating subsidy you will receive.”

The EAC is tightening the allowed distribution margin (the difference between total costs of distribution and sale and power purchase costs) for SPDs. There is always a danger that if the distribution margin becomes too small, SPDs will no longer be commercially viable, raising the question of who will take over for SPDs if they go out of business.

**Regulation of wholesale tariffs**

Wholesale tariffs for electricity sold to distribution franchisees are also regulated. They range from CR 508 to CR720 ($0.127–$0.18) per kWh, depending on whether the electricity is coming from EdC or a private transmission line, the voltage of the connection, and the transmission line distance.\(^{13}\) A comprehensive spreadsheet-based model is used to calculate relevant wholesale tariffs based on depreciated costs, expected electricity sales, and other inputs.

**Commercial Aspects**

Grid-interconnected mini grids in Cambodia have overwhelmingly adopted the distribution franchise model (referred to as SPDs in other countries), purchasing electricity at wholesale from the national utility for resale to retail customers. As of July 2016, an estimated 250 private sector distribution franchisees were in operation. In 2015 the typical distribution franchisee reselling EdC electricity had about 2,800 customers.\(^{14}\) A review of license holders indicates that small, local family businesses generally own these projects.

With the expansion of the EdC transmission network into the service territory of isolated mini grids, licensees have been eager to connect to EdC (or in some cases, cross-border utilities) as soon as possible. Connection allows the mini grid operator to get rid of the burden of operating and maintaining a diesel generator while retaining opportunities for profits.

With electricity tariffs to end users dropping from CR 3,000–CR 4,000 ($0.75–$1) per kWh to CR 800 ($0.20) or lower, customers now purchase more electricity. In 2014 the typical customer connected to national grid power (whether as a direct EdC customer or a customer of a distribution franchisee) consumed 3,064 kWh; the typical isolated mini grid customer consumed just 324 kWh, according to the EAC’s 2015 annual report.

Moreover, the EAC typically allows a month or more time lag in reducing tariffs, to reflect the change to the cheaper grid-connected source of electricity. This period of high revenues/low costs provides a cash-flow boost that is useful in covering the costs incurred for the new equipment required to interconnect to the main grid.
In many countries, utilities want to take over electricity distribution to retail customers once their lines reach a village. This has not been the case in Cambodia. EdC supported the conversion of isolated mini grids to SPDs because it lacked the personnel and funds needed to expand the grid to reach individual distribution networks. Conversion allowed EdC to focus on building out medium-voltage networks to existing mini grid distribution networks, providing more people with electricity than would have been possible if EdC had also focused on building its own (in many cases duplicative) retail distribution network. It made business sense for EdC to support the isolated mini grids, which converted to SPDs. By taking this approach, EdC avoided the costs of connecting new customers, introducing them to grid-based electricity, and seeking out customers with larger productive loads. It left the heavy lifting of market development to the owners and operators of isolated mini grids.

Distribution franchisees and isolated mini grids have found it difficult to finance investments in improving the quality and coverage of their distribution networks. Mini grids and distribution franchisees in rural areas have had limited options, including borrowing from relatives and from informal lenders at high interest rates.

To help expand access to electricity, in 2004 the government of Cambodia issued Royal Decree NS/RKT/1204/048, which established the Rural Electrification Fund (REF). The fund was initially co-capitalized by the World Bank and the Cambodian government. Under this initial program, the World Bank provided assistance of $45 per connection for 50,000 new connections in rural areas.15 In August 2012, operation and funding of the REF was transferred to EdC, which expanded programs.

Two REF programs support mini grids. The Program for Power to the Poor (P2P) provides interest-free loans to households for interconnection fees, in-house wiring, and the cost of wires from the connection point to the house. The maximum loan is CR 480,000 ($120), with a maximum tenor of 36 months. Collection of loan payments is done by the mini grid licensee as part of bill payment.

The Program for Providing Assistance to Develop Electricity Infrastructure in Rural Areas provides financing for construction of distribution networks and other electricity supply infrastructure for licensees that have licenses of at least five years. EdC uses population density and economic development indicators to decide how much funding a mini grid is eligible to receive:

- In areas with low density and low economic development, the REF provides grants of up to 30 percent of the project infrastructure cost, with up to an additional 60 percent in the form of an interest-free loan.
- In areas with medium population density, where electrification may not be profitable, if the licensee had to pay interest on a loan, the REF provides interest-free loans. These loans have a limit of 50–60 percent of the cost of the infrastructure owned by the licensee, cannot exceed $300,000 per project, and have a maximum tenor of eight years. In the event of default, the license reverts to EdC.
- In areas with high population density, where electrification is more economically viable, the program was designed to provide bank guarantees. No loan guarantees appear to have been
made, however, because the Ministry of Economics and Finance has been reluctant to approve them.

Funds for the interest-free loans and grants come from the German KfW and EdC.

By 2016 most higher-density areas had been covered. The remaining areas are largely recipients of interest-free loans or both grants and interest-free loans.

**Technical Aspects**

Electricity does not flow from the distribution franchisee (SPD) back to the main grid; the flow is unidirectional rather than bidirectional. If they are retained, generators are used only as backup when power from the main grid is not available. When operated, the remaining generators are thus isolated from the main grid. For this reason, there is no need to synchronize generators with the grid (in contrast to the SPPs in the Sri Lanka and Indonesia described in this report). Therefore, the arrival of the main grid and subsequent interconnection as distribution franchisee involves relatively uncomplicated technical upgrades. Indeed, most of the upgrades to poles, conductors, and metering to be grid ready will have already occurred as a condition of the consolidated distribution/generation license. The actual interconnection with the national grid generally requires only a transformer, a meter, and fused switchgear that disconnect loads in the event of an overcurrent condition.

### 2.4 CONCLUDING OBSERVATIONS

Cambodia’s experience with mini grids is unique: No other country appears to have successfully converted so many isolated mini grids into connected SPDs. Several reasons may have contributed to its success:

1. The regulator used the “stick” of its licensing authority to induce private mini grid operators to invest money to improve their distribution systems so that they could operate as SPDs once connected to the EdC grid.
2. EdC viewed the mini grids and later the SPDs as good for its own commercial viability.
3. The national government was willing to provide operational subsidies to the SPDs, which were required if they were to charge a uniform retail tariff that did not recover their costs. At least so far, the distribution margin has been high enough for a well-run mini grid to be commercially viable as a connected SPD. These margins were enabled in part by the fact that customers were accustomed to very high tariffs, as a consequence of widespread earlier use of diesel generation.
4. Mini grid owners were motivated to operate efficiently and expand into neighboring villagers to achieve economies of scale.
REFERENCES


In 1994, when Sri Lanka was in the midst of a civil war, only about 38 percent of the population had access to the grid—and the percentage was even lower in rural areas. By 2016 about 98 percent of Sri Lankan households had access to grid-quality electricity.

Much of the growth in electrification over the past 20 years was driven by expansion of the central grid. But some rural electrification was made possible by the fact that Sri Lanka had numerous small hydropower sites that could be used to generate electricity.

Over the past 20 years, two types of entities—Village Electricity Consumer Societies (VECS) and small power producers (SPPs)—came into existence to develop these sites, each serving a very different market. VECS are voluntary community organizations that were created to build, own, operate, and manage individual, run-of-the-river pico- and micro-hydropower projects to supply electricity to rural households in villages that had not yet been connected to the main grid of the national utility (the Ceylon Electricity Board [CEB]).

SPPs were typically owned by private operators. Between 1996 and 2011, private operators developed more than 100 mini- and small-hydropower sites, most of them larger (up to 10 MW), main grid–connected, mini-hydro projects. In contrast to the VECS, the SPPs were built for the sole purpose of selling electricity at wholesale to the national utility, under a standard power purchase agreement. As the SPPs did not make retail sales at the local distribution level, they were not mini grids.

This case study examines only the VECS. It describes how they came into existence; how they were financed, operated, and regulated; and what happened to their operations after the CEB grid arrived in their villages.

### 3.1 Powering Households before a Village Is Connected to the Main Grid

Between 1997 and 2011, VECS built more than 260 individual pico-and micro-hydropower projects to serve isolated villages. These “village hydro projects” (VHP) were small hydropower projects ranging in size from 3 kW to 55 kW of installed generating capacity and serving 3–80 households. The median system produced 7.5 kW and supplied 27 customers, largely within a 2-kilometer radius. It is estimated that the VECS created a total of about 4 MW of installed generating capacity and provided electricity to about 10,000 rural households. In a sample of five VHPs, the unit cost per installed kW of generating capacity ranged from $1,543 to $2,266 in 2011 (Cabraal 2011).

**Public-Private Partnership**

The 260 hydro projects owned and operated by the VECS were the result of two government of Sri Lanka programs supported by the World Bank: Energy Services Delivery (ESD) and Rural Energy for...
Rural Economic Development (RERED). The two programs created credit lines that operated from 1997 to 2012. Using credit lines, loans to the VECS were made by Sri Lankan commercial banks, at more favorable terms, because they were supported by World Bank credit lines. The credit lines were administered by the government of Sri Lanka, with an interest rate tied to the average weighted deposit rate. In the absence of these credit lines, it is unlikely that the banks would have been willing to make loans to the VECS, because the banks did not have access to other sources of long-term capital. The credit lines gave the Sri Lankan banks access to a long-term source of capital specifically targeting the VECS. The Administrative Unit, a group within the Development Finance Corporation of Ceylon (DFCC) bank, administered the program. In addition to the credit line, it administered grants from the Global Environment Facility, channeled subsidies from the government of Sri Lanka, and provided extensive technical assistance to the VECS.

A unique feature of the program was the melding of a community’s need for electricity with targeted financial incentives for private sector consultants to assist communities in creating VECS. Selected local consultants received monetary payments if they created VECS that were able to build and operate VHPs. Under this program, a private consultant (called a “project preparation consultant”), usually an individual or firm with an engineering background, received a payment of $8,000 from the Administrative Unit for each mini grid project. This payment consisted of a down payment of $3,200 upon a review of the technical design, an additional $2,400 upon verification of successful installation, and $2,400 after six months of operation.

The consultants were required to perform a range of organizational and engineering tasks, which included the following:

- identifying viable hydropower sites
- engaging with the community
- helping form VECS
- helping VECS obtain financing
- designing, procuring, and installing the project and the necessary distribution facilities, based on guidelines and standards created by the DFCC Bank and financed by the World Bank’s RERED and ESD projects
- helping the VECS obtain all required statutory approvals
- training people in the village to operate and maintain the hydro facility (see Cabraal 2011)

To ensure that the consultants were competent to perform these tasks, they had to demonstrate a minimum level of knowledge and experience in small hydropower generating projects. In granting registration to applicants, the Administration Unit looked for both engineering and “social mobilization” skills.

Before the two World Bank projects, various nongovernmental organizations (NGOs), such as the Intermediate Technology Development Group (ITDG, now known as Practical Action) obtained
funding from donors such as Rotary International to build micro-hydropower facilities in a few remote villages. These pioneering projects “proved the concept.” Building on these experiences, the World Bank–funded ESD program provided funding and technical assistance to scale up the concept and moved from pure grant funding to semi-commercial financing. Financing was combined with targeted technical assistance provided by mostly private consultants operating under a performance-based incentive system.

**Financing**

The initial (pre-ESD) village hydropower projects were 100 percent financed by grants. Over time projects were able to obtain financing from about 10 local commercial and regional development banks that had access to a World Bank credit line, which allowed the banks to offer better terms. The credit line demonstrated that the projects were perceived as being financially viable by commercial banks at least for the period of the loan. For a 10 kW VHP that served 40 households with an overall cost of about $16,900, the typical financing plan for later projects was funded as follows:

- commercial bank loan: 35 percent
- co-financing grant from the Global Environmental Fund: 29 percent
- equity from VECS members: 18 percent
- provincial council grant: 18 percent

The terms of the commercial bank loans are not public because they are in private loan agreements. However, one knowledgeable observer estimated that in 2010 the typical loan had a 16 percent interest rate and a term of four to five years. This rate was considerably lower than the estimated 48 percent interest rate that local nonbank lenders were charging rural households at the time. Some of the commercial bank loans were made to the VECS; others were made to individual members of the VECS.

A unique feature of the VECS loans was the use of cross-guarantees. Each household was responsible for part of a loan, and households guaranteed each other’s payments.

The success of the VECS is attributable largely to four elements of the program:

- targeted and timely technical assistance from local private consultants, who were paid for results
- access to commercial bank financing, which was supported by a World Bank credit line
  - performance-based grants of $600–$800 per kW of installed micro-hydropower capacity, up to a maximum of $30,000
- endorsement of projects by provincial councils, which enhanced their credibility
Good design does not automatically lead to good outcomes. The overall program greatly benefited from the competence and diligence of the staff within the DFCC’s Administrative Unit. Unlike the private mini grid projects of Cambodia, the VECS of Sri Lanka were not spontaneous bottom-up projects. They were nurtured projects created under a well-designed and well-implemented government program that was co-designed and co-financed by the Sri Lankan government and donors.

DFCC’s Administrative Unit established norms for the technical quality of the individual installations. It required that both design and implementation be performed by the registered project preparation consultant. It also mandated that a registered equipment supplier supply equipment and that the equipment be tested at an independent laboratory. Qualified engineers were hired to review whether the required technical specifications were met at the design, installation, and post-installation stages. Hence, the Administrative Unit was the de facto regulator of technical quality. This practice is common in many countries. Quality of service (at least at the level of input specifications) is typically assessed by the grant-giving agency rather than the national electricity regulator. The rationale is that the grant-giving agency needs to ensure that it is getting value for money.

**Tariff Regulation**

Many of the VECS began operating long before the Public Utilities Commission of Sri Lanka (PUCSL), Sri Lanka’s electricity regulator, came into existence, in 2003. However, even after PUCSL was created, it did not regulate the retail tariffs the VECS charged their members.

Two explanations have been offered as to why PUCSL did not regulate the prices charged by the VECS. The first is that VECS were considered captive generation (that is, a form of self-supply), which was usually not subject to tariff regulation.

The second is that the monthly payments made by members to the VECS could be viewed as membership subscription fees rather than tariff payments. This view is supported by the fact that the “customers” of the VECS are also its “owners,” implying that members would have no incentive to overcharge themselves for the electricity the VECS provide. The government electricity regulator was therefore not needed to protect VECS members from high prices. In fact, the opposite criticism—that VECS membership fees were too low—has been made. Fees covered operating expenses and loan repayments (during the loan period), with no provision for depreciation or a return on invested capital.21

Setting tariffs too low is not unique to Sri Lankan VECS. It seems to be the norm for community-owned pico, micro, and mini grids around the world.22 These community-owned entities typically charge tariffs that are too low to maintain commercially sustainable operations over the long run. This concern is not great if the distribution assets of the community-owned system are replaced with new distribution assets paid for by a larger national or regional utility when the main grid reaches the village. It is a concern if the system expects to operate over a long period of time. In that case, the system needs to create a depreciation fund to pay for future replacements of the assets.
3.2 WHAT HAPPENED AFTER THE MAIN GRID ARRIVED?

Going out of Existence

VECS flourished between 1997 and 2012. As the main CEB grid expanded rapidly into villages served by them, many of them went out of existence, as many of their members became customers of the CEB.

A 2014 survey by the Energy Forum found that more than 100 VECS disappeared after the CEB grid arrived. When the CEB grid reached a village that had been served by a VECS, about 60 percent of VECS members typically became customers of CEB—usually households closer to the center of the village and households that could afford the connection charge of about $50. The remaining 40 percent of households, who stayed with the VECS, were usually located farther away from the village center. They continued to be supplied by the VECS, because they were not able to afford the higher connection charge necessary to bring CEB distribution lines to their more distant locations. Once the CEB main grid arrived, two electricity distribution systems operated in the village for several years.

It is likely that most VECS will eventually disappear as viable retail electricity suppliers. The total revenue they will receive from a shrinking number of households will be insufficient to pay for their operational expenses, let alone any major repairs, pushing them into a financial death spiral.23 There are two strong economic reasons why VECS members chose to switch to the CEB. First, CEB offered a significantly lower price per kWh. As soon as a village is connected, households in the village can access CEB’s highly subsidized national lifeline tariff, under which any household that consumes 90 kWh or less per month pays $0.017–$0.067 per kWh.24 This rate is much lower than CEB’s estimated cost of supply to rural households of $0.1351 per kWh. In contrast, if villagers continue to take service from the VECS, they pay about $0.25 per kWh.

Second, CEB offered a higher level of service. It was able to provide electricity 24/7 and without any major restrictions on the household appliances that could be connected. In contrast, VECS members were usually not allowed to use irons or rice cookers in the evening or morning peak hours, because the VECS electrical system did not have sufficient generating capacity to meet these loads. VECS members were also not allowed to connect refrigerators, which, if widely used during peak hours, would strain the maximum available capacity of the system and lead to brownouts or blackouts. For a typical 10 kW system serving 40 households, each household was limited to maximum peak consumption of 250 W, which was sufficient to light a home with a few compact fluorescent light bulbs and a small TV or radio. Connecting to CEB distribution lines allowed households to use more appliances without restrictions on the time of their use (UNDP 2012). In one typical system, the average household consumption went from about 50 kWh per month before interconnection to 90 kWh after interconnection (conversation with Wathsala Herath, Energy Forum, October 28, 2017).
**Becoming a Small Power Distributor**

Most stakeholders in Sri Lanka do not think that conversion from an isolated community-owned micro grid to a main grid–connected SPD (as happened in Cambodia) is a viable option for VECS. In order to become an SPD, a VECS would need to become a cooperative (a formal legal entity that can sign contracts) rather than remain a VECS (a community welfare organization). There is no legal barrier to such a conversion. If the conversion takes place, the Electricity Act 2009 states that a cooperative can apply for a distribution license (Clause 9 (3) (d)). It would be relatively easy for a VECS to convert itself into a cooperative under the 1972 Cooperative Societies Law.

Such conversions have not happened in Sri Lanka, for at least two economic reasons. The first is that most VECS would have to build totally new distribution systems to meet CEB standards. In most cases, the existing distribution systems would have to be totally replaced rather than just upgraded, a change that would be very expensive. The second reason is that even if the investment to build a new distribution system were 100 percent financed from grants, most VECS would be too small to operate the new system on a commercially viable basis.

Consider the revenues that would be required to operate a commercially viable distribution system in Sri Lanka. Once connected, VECS members (now cooperative members) would expect to pay the same tariffs as similarly situated rural customers of the CEB. In effect, the CEB’s retail tariffs would be a de facto cap on any new distribution cooperative.

But it would be commercially impossible for a new distribution cooperative to charge tariffs as low as the subsidized tariffs that CEB currently charges customers who consume 90 kWh or less. The CEB can spread the cost of this subsidy into the tariffs of its other customers; the cooperative would be unable to do so.

Consider the case of a cooperative that has 50 customers, each consuming 60 kWh a month (higher than the average national consumption). Using CEB’s tariffs, the cooperative’s gross monthly revenues would be 50 * ([SL Re 2.50 * 30]) + [SL Re 4.85 * 30] + SL Re 60) = SL Re 14,025 (less than $100), where SL Re 2.50 is the per kWh charge for the first 30 kWh of consumption a month, SL Re 4.85 is the per kWh charge for the next 30 kWh of consumption, and SL Re 60 is a monthly fixed charge. This level of revenues would not suffice even to pay the salary for one operational staff member, let alone purchase bulk power. The typical VEC would simply be too small to commercially sustain a distribution cooperative whose members expect to be charged the same retail tariffs that CEB charges rural customers.26

In Nepal, where more than 240 small community-owned distribution systems have been created, the rule of thumb is that the distribution system needs to serve at least 200 customers in order to be financially viable (Energypedia 2014). What is the difference between Sri Lanka and Nepal? In Nepal community-owned grid connected distribution systems, called Community Rural Electrification Entities (CREEs), never operated as isolated mini grids. From Day 1 they were connected to the grid operated by the government-owned Nepal Electricity Authority (NEA). The CREEs buy bulk power from NEA under subsidized tariffs.27 They also receive large capital cost subsidies. Initially, the government of Nepal (through NEA) paid 80 percent of the capital costs of
the village distribution system. This subsidy was later raised to 90 percent. Under the rules
governing the program, NEA is deemed to be the formal owner of the distribution system, and the
CREEs pay a small leasing fee to NEA. CREEs are required to charge their small customers the same
tariff NEA charges its grid-connected customers. It appears that the CREEs are financially viable
because they have few capital costs, they pay a subsidized bulk tariff to NEA, and their functions are
limited to bill collections and low-level maintenance. It does not appear that there is political will or
need to replicate such subsidies in Sri Lanka.

**Becoming a Main Grid–Connected Small Power Producer**

VECS could also legally become SPPs when the main grid arrives in their village. But by 2016, only 3
of the more than 250 VECS had done so. These three projects had installed capacities of 12, 21, and
45 kW. In order to be able to sign the standard power purchase agreement with the CEB, the VECS
were reconstituted as limited liability companies, changing their legal identity from a Village
Electricity Consumer Society to a Village Electricity Consumer Company.

Each of the three limited liability companies has three shareholders: the community, the Federation
of Electricity Consumer Societies (FECS), and the Energy Forum, is a nonprofit organization that,
among other things, promotes the adoption of renewable energy and distributed generation
([http://www.efsl.lk/](http://www.efsl.lk/)). Under the terms of the agreement to create a limited liability company, the
community receives about 40 percent of the income from electricity sales to the CEB. These funds
go directly into the bank accounts of individual community members. The remaining 60 percent of
income is split between the Federation and the Energy Forum. Membership on the board of
directors is split among the three shareholders: two directors represent the village consumers, and
three directors represent the FECS and the Energy Forum. In day-to-day operations, the FECS
provides management know-how, and the Energy Forum provides technical expertise.

The first interconnection of a VECS was for Atheliya, with installed capacity of 45 kW. The total cost
of the interconnection was about $35,000. In the first full six months after Atheliya became an SPP,
the total income received for sales to the CEB was $11,000. After paying the operator and other
operating expenses, the remaining net income was split among 85 individual member accounts.

In a 2016 survey of 200 VECS, the Energy Forum determined that 110 are no longer operating.
Energy Forum estimates that about 50 of them could become SPPs. To make a successful
conversion, the Energy Forum believes that the following conditions would have to be met:

- Generating capacity must be at least 20 kW.
- The distance between the CEB grid and the VECS powerhouse should be less than 1.5
  kilometers, in order to minimize the investment required for interconnection.
- There must be evidence of community interest.
- Funding should be available to connect remaining households (if any) to the CEB grid.
- The VECS should have the ability to generate adequate funds (through bank loans or
  additional equity) to finance the connection to the CEB grid.
**Regulatory requirements**

If a VECS terminates its retail supply business and becomes an SPP, it switches to selling its entire output to CEB. Like the more than 100 small privately owned hydro-power SPPs, these newly created community-owned SPPs sell to CEB under a technology-based feed-in tariff. The feed-in tariff is the same for both private and community-owned SPPs. Currently, CEB buys electricity from both types of SPPs at a price of SLR 17.85 (about $0.12) per kWh in year 1, with an operations and maintenance escalator clause. After 8 years, and again in year 15, the price received by the SPP drops. The SPPs do not receive a separate capacity payment, because they cannot guarantee capacity. On average, privately owned SPPs are considerably larger, with installed capacity of 2 MW versus a median installed capacity of 7.5 kW for VECS. They generally also have lower average costs of production.

In order to operate an SPP, the SPP owner must have the legal authority to sign a standardized power purchase agreement (SPPA) with the CEB. Under Sri Lankan commercial law, a VECS, cannot enter into such a contract. However, a VECS can become a registered village cooperative. Doing so is relatively easy and inexpensive. Once the VECS becomes a cooperative, it has the legal authority under the Cooperatives Act to sign an SPPA with the CEB. The cooperative has the option of becoming a shareholder in a limited liability company.

**Other obstacles**

At least three barriers to conversion appear to prevent more conversions. First, converting requires funding to pay for technical assistance on the legal, economic, and technical issues that need to be resolved for a successful conversion. When the VECS first came into existence, the World Bank’s RERED project paid for the needed technical expertise by hiring local Sri Lankan consultants. Funding for technical assistance is no longer available.

Second, investment capital is needed to make the conversion. Conversion requires the payment of application fees and the upgrading of the penstock, poles, transformers, and lines to transformer. It would be difficult, if not impossible, to raise the necessary capital from VECS members.

Third, under current rules, a number of approvals (described below) are required to make the conversion. The SPP must obtain both a Provisional Approval and an Energy Permit from the Sustainable Energy Authority (SEA). It must obtain a letter of intent to accept the interconnection from the CEB as well as a generation license from the national regulator. In addition, a VECS that wishes to operate as an SPP must obtain an environmental clearance from Sri Lanka’s national environmental agency. This clearance takes time, because the national environmental agency will usually send the application to its provincial office. No action can be taken until the provincial environmental office gives its clearance. VECS that wish to operate as SPPs have complained that the requirements they face from the central environmental authority, the national electricity regulator, and the CEB are the same requirements as larger projects and that these soft costs kill the financial viability of many potential conversions.
Adopting a Different Ownership Model

In theory two other post-interconnection business options might be available to VECS. Both involve private investors. The first would involve a complete buyout of the VECS generation facilities by a private entity. Presumably, once the buyout occurs, the private entity could make investments to expand the installed capacity of the existing micro-hydropower generator so that it could sell more electricity to CEB. Government officials in Thailand, which had similar community-owned hydropower facilities, opposed this option. They argued that it would not be fair for a private investor to benefit from facilities that had been financed, at least in part, by government money. Presumably, the private investor could pay back the government for the earlier grants, but there are no reports that this happened in Thailand. Similarly, it appears that the SEA will not allow this option. Its board has prohibited VECS from selling out completely to private individuals or companies.

A second option would be for the VECS to create a joint venture with a private individual or company, forming a community-private partnership. Under Sri Lankan law, the VECS members must retain 15 percent of the ownership of the new joint venture, which would have a recognized legal identity so that it would be able to sign SPPAs with the CEB. A major advantage of this option is that the joint venture company would presumably have easier access to financing to improve or expand the existing generating facilities than would a stand-alone community-owned cooperative.

The principal financial incentive for a private investor would be the possibility of selling wholesale power to the CEB under the existing feed-in tariffs. In most instances, the private partner in the joint venture would want to increase the size of the generator in order to be able to sell more wholesale power to the CEB. In many case, the VECS initially installed generating capacity that probably did not take full advantage of the electricity-generating potential of the stream. The benefit of a joint venture to the community is that it would provide access to private capital, professional operations and maintenance of the generating facilities, and the possibility of a future regular revenue stream that could go to a community welfare organization or individual household stakeholders in the community. To date, no VECS–private developer joint ventures have been created in Sri Lanka. More detailed analysis is required to better understand the legal, economic, and political impediments to creating such joint ventures.

3.3 Technical Aspects of Interconnection

Even when serving isolated villages, Sri Lanka’s mini grids were required to follow stringent technical standards in order to receive grant money under the RERED. The standards were lower than the standards required by the CEB on its distribution facilities, however.

When the main grid arrived, the VHS needed to change its mode of operation from one in which the micro-hydropower unit sets its own frequency (through the use of an electronic load controller) to one in which it is synchronized with the national grid (and therefore generating in phase with the national grid). Connection to the national grid requires the addition of relay equipment that ensures that the VHS safely connects when electrical conditions are appropriate, and quickly disconnects in the event of an electrical disturbance on the main grid. These relays depend on the type and size of
generator used. For projects under 100 kW, the most common arrangement in Sri Lanka (and the simplest technically) uses an induction generator\textsuperscript{29} with relays that will disconnect in the following conditions: over-current, under/over voltage, and under/over frequency.\textsuperscript{30} Programmable relays for interconnection of these small projects have been designed and manufactured in Sri Lanka. They are reported to be affordable for a complete set of switchgear.

In addition, interconnection to the grid generally requires the installation of poles, electric lines, and a meter. The three VECS that have connected to the CEB grid have connected at low voltage (400 V). Interconnection of micro-hydropower projects requires a load flow study to ensure that the voltages in the CEB network will not be adversely affected (either too high or too low) by the presence of the new generation source. CEB charges a discounted price for this load flow study of about $700.

### 3.4 CONCLUDING OBSERVATIONS

The Energy Forum catalyzed the interconnection of three formerly isolated mini grids to the national grid and their conversion to SPPs, working diligently to chart a regulatory and financial path for interconnection. It is unclear whether grid interconnection of formerly isolated mini grids will expand substantially beyond this small number. Most VECS were abandoned when the CEB grid reached the villages they served, for several reasons:

1. CEB offered lower (highly subsidized) prices and better service (more hours of service, generally without connection limitations on the size of appliances that could receive service).
2. With a median size of 27 customers, the VECS were too small to survive as commercially viable SPDs.
3. The distribution facilities were not built to meet CEB standards.
4. VECS did not have access to sources of financing that would allow them to finance the cost of interconnection equipment and expansion of their generation capacity.
5. The regulatory requirements to obtain SPP status had been designed for larger generators and were too burdensome for the smaller generators operated by VECS.
6. VECS were widely viewed as a transitional arrangement that could provide a basic level of grid electricity until the CEB arrived with better service at a lower price.

### REFERENCES


Mountainous remote island terrain and a supportive policy environment in Indonesia led to the construction of more than 1,300 isolated micro-hydro-powered mini grids, which provide electricity to isolated villages (Suryani 2013). Most of these mini grids were funded by government grants and built by local private sector companies, often in partnership with community organizations and assisted by domestic and international nongovernmental organizations (NGOs).

The transition from isolated to grid-connected mini grids has been a challenge—but not an impossible one. Nine formerly isolated micro-hydropower mini grids have connected to the national grid (Perusahaan Listrik Negara [PLN]), selling electricity at wholesale to it under government-specified feed-in tariffs. Another 50 mini grids co-exist next to the national utility grid. About 150 others were abandoned with the arrival of the main grid.

4.1 Micro-Hydropower for Village Electrification

The history of micro-hydropower in Indonesia is rooted in the geography of the country. Thousands of inhabited islands make it prohibitively expensive to provide grid electricity to the entire country. At the same time, mountainous topology and a wet tropical climate create mountain streams suitable for micro-hydropower.

For decades both the government and NGOs recognized the potential of micro-hydropower mini grids to provide rural electricity at lower cost than alternatives. On the government side, Indonesia’s Ministry of Energy and Mineral Resources began developing individual micro-hydropower projects in 1995, with a goal of electrifying remote areas. A decade later, the Ministry of Cooperatives and Small and Medium Enterprises came on board, funding additional projects, with the main goal of generating rural income. All told, seven Indonesian ministries have implemented community micro-hydropower projects.

Deployment of village micro-hydropower started in earnest in the mid-1990s. As of 2013, the vast majority (1,033 projects) were funded by the government (often using funds from international donors but managed by an Indonesian ministry). Communities and civil organizations built 199 projects, PLN and other companies built 79, and “other cooperation, partnerships and unknown” accounted for an additional 31 (Fadhilah, Suryani, and Schultz 2013).

In government projects, assets are owned by the local (district or provincial) government, and the project is managed by a local community-based organization. NGO-built projects are owned and operated by community-based organizations. At the village level, a team that generally includes two operators, a director, and a secretary operate average-size projects.
Isolated micro-hydro mini grids in Indonesia vary in capacity from a few kW to hundreds of kW, with most projects in the 5–40 kW range (Suryani 2013). A 2015 study commissioned by the Policy and Operations Evaluation Department (IOB) of the Netherlands Ministry of Foreign Affairs found that electricity consumption is not metered in most communities with micro-hydropower (Peters and Sievert 2015). Rather, households pay for electricity based on the type and number of appliances used.

A minority of communities use load limiters (miniature circuit breakers) and base the tariffs on their current rating. Some communities offer special lifeline tariffs for the poorest members. Communities with micro-hydropower typically set their own tariffs, with the aim of covering the costs of operation and maintenance and future repairs. In practice, tariffs are often insufficient to pay for repair services when needed (Peters and Sievert 2015).

Indonesia’s burgeoning private micro-hydropower sector industry typically supplies and installs the turbines, generators, and civil works for these projects, as well as equipment to connect micro-hydropower projects to the national grid. Starting in the early 1990s, donor-funded capacity-building programs helped the private sector acquire the skills needed to implement high-quality micro-hydropower projects and provide post-installation services, particularly around the city of Bandung, the capital of West Java (Table 4.1).

Table 4.1 Donor Programs for Scaling Micro-Hydropower in Indonesia

<table>
<thead>
<tr>
<th>PROGRAM</th>
<th>DURATION</th>
<th>FUNDING AGENCY</th>
<th>KEY ASPECTS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mini Hydro Power Project (MHPP)</td>
<td>1990–96</td>
<td>GTZ</td>
<td>• Developed and introduced technology to NGOs and small-scale equipment manufacturers</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Collaborated with ITDG (United Kingdom), Skat Consulting (Switzerland), and FAKT (Germany)</td>
</tr>
<tr>
<td>Mini Hydro Power Project (MHPP)</td>
<td>2000–05/06</td>
<td>GTZ</td>
<td>• Transfered standardized cross-flow turbine designs to local equipment manufacturers</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Provided policy assistance to the government to enable small power producers to interconnect and sell power to the national grid</td>
</tr>
<tr>
<td>Energising Development Phase I</td>
<td>2006–09</td>
<td>German-Dutch Energy Partnership</td>
<td>• Targeted the development and strengthening of community-based micro-hydropower ownership models and institutional setups</td>
</tr>
<tr>
<td>(Endev I)</td>
<td></td>
<td></td>
<td>• Provided capacity building for community-based micro-hydropower plants constructed by various government and nongovernment programs</td>
</tr>
</tbody>
</table>
Good-quality equipment and installations increased the sustainability of many projects, which, in turn, helped convince the Indonesian government that micro-hydropower was a viable electrification solution for remote villages with suitable water resources. It also made it easier for micro-hydropower associations to lobby for policies that support mini grids and their integration with the grid. Two micro-hydropower associations, Yayasan Mandiri and the Asosiasi Hidro Bandung (AHB), served as focal points for technology innovation and actively lobbied for enabling policies and programs.

Thanks to a combination of technical capacity building, supportive policies, and demand for electricity in remote areas in Indonesia (and abroad), a strong domestic micro-hydropower industry grew. By 2016 more than 350 specialized engineers, technicians, and project developers were believed to be working on mini grid projects in Indonesia. In addition to meeting local demand, the Indonesian micro-hydropower industry has looked overseas, exporting turbines and control systems to Cameroon, Ethiopia, Germany, the Lao People’s Democratic Republic, Madagascar, Malaysia, Mozambique, Nepal, Papua New Guinea, the Philippines, Switzerland, Tanzania, Uganda, the United Kingdom, and Zaire.31 These companies not only build micro-hydropower turbines and controls, they also manufacture the equipment necessary to connect micro-hydropower project to the grid (Box 4.1).
4.2 REGULATIONS FACILITATING GRID INTERCONNECTION

Indonesia’s regulations enabling interconnection of mini grids have evolved over many years. The Electricity Law of 1985 established PLN as the country’s national utility, with monopoly control over all aspects of the electricity sector. PLN’s financial viability was damaged during the economic crisis of the late 1990s; in response, the Electricity Law of 2002 liberalized and allowed for private sector participation in the sector. PLN maintained control of the transmission and distribution system, but both generation and retail sales were opened up to private participation. For a brief period, nationwide retail electricity tariffs were allowed to be market based, and the Electricity Market Supervisory Agency was established to provide independent regulatory oversight.

In 2004 the Indonesia’s Constitutional Court deemed the 2002 law unconstitutional and ruled that electricity should be delivered exclusively by a state-owned agency. Annulment of the 2002 law essentially reenacted the 1985 law. As a compromise between the 1985 and 2002 laws, the government passed the Electricity Law of 2009, which allowed the private sector to generate and distribute electricity to end-use customers, though PLN retained a “right of first priority.”

Regulations under the law were generally implemented through ministerial decrees. In 2002 Indonesia adopted Ministerial Decree 1122/K/30/MEM on Small Distributed Power Generation Using Renewable Energy, known by Indonesians as PSK Tersebar. It required PLN to purchase...
electricity from cooperatives, the private sector, and government company small power producers (SPPs) below 1 MW. It standardized feed-in tariffs based on PLN’s location-specific generation costs.

In 2009 a similar decree was issued for projects of 1–10 MW; it provided regional governments a greater role in licensing and allowed for region-specific feed-in tariffs. Critics complained that the decree also increased bureaucratic requirements involved in obtaining a power purchase agreement.

Decrees in 2012, 2014, 2015, and 2016 refined feed-in tariffs based on technology type, years of operation, and voltage of interconnection; denominated tariffs in U.S. dollars; and established regional concessions (Table 4.2). All of the decrees except the 2016 one focused almost entirely on the level and structure of feed-in tariffs.

Table 4.2 Policies that Apply to Independent Power Producers of Renewable Energy in Indonesia

<table>
<thead>
<tr>
<th>YEAR</th>
<th>POLICY NUMBER AND NAME</th>
<th>KEY ATTRIBUTES</th>
</tr>
</thead>
</table>
| 2002 | Ministerial Decree 1122/K/30/MEM: Small Distributed Power Generation Using Renewable Energy (known as PSK Tersebar) (IEA 2002) | • Requires PLN to purchase from cooperative, private, and government small power producers (SPPs)  
• Covers plants of less than 1 MW  
• SPP feed-in-tariff set to 80 percent of PLN’s location-specific electricity base price for medium voltage (60 percent for low voltage) |
| 2009 | Ministerial Decree No. 31/2009: Tariffs for Small and Medium Scale Power Generation Using Renewable Energy and Excess Power (IEA 2009) | • Requires PLN to purchase from small- and medium-scale renewable energy plants up to 10 MW  
• Sets feed-in-tariffs at Rp 656 (about $0.064) per kWh x F if interconnection at medium voltage and Rp 1,004 (about $0.098) per kWh x F at low voltage, where F is a location factor for four regions that ranges between 1.0 (for Bali) and 1.5 (for Papua)  
• Allows PLN to purchase electricity at cost higher than above-mentioned tariffs based on its Own Estimation (OE) price, subject to approval by Minister of Energy and Mineral Resources  
• Exempts projects interconnected before 2009 |
| 2012 | Ministerial Decree No. 4/2012: Electricity Purchase from Small and Medium Renewable Energy and Excess Power (IEA 2012) | • Differentiates tariff levels based on installation type, location, and voltage of grid interconnection  
• Does not specify how long eligible renewable plants will benefit from introduced tariff |
| 2014 | Ministerial Decrees 12/2014 and 22/2014, on mini-hydro feed-in-tariff regulation (Minister of Energy and Mineral Resources, 2014a, 2014b) | • Bases feed-in-tariffs on factors in Decree No. 4/2012 plus years of operation and use in Rp per kWh  
• Includes cost of transmission line between mini grid and PLN grid in feed-in tariff  
• Sets power purchase agreement without tariff negotiation or price escalation |
Establishes detailed mandatory procedure and timelines for
development and execution of power purchase agreement

**2015**

Ministerial Decree No. 19/2015, on mini-hydro feed-in-tariff regulation (Minister of Energy and Mineral Resources 2015)
- Denominates feed-in-tariffs in U.S. cents per kWh
- Subjects existing projects to feed-in-tariff revisions

**2016**

Ministerial Decree No. 38/2016, on acceleration of electrification in rural areas by setting up small-scale electric power supply businesses (Minister of Energy and Mineral Resources 2016a)
- Allows private business entities to provide electricity to currently unelectrified regions through geographically based business area concessions
- Establishes feed-in tariffs for grid-connected renewable energy mini grids

and Ministerial Decree No. 39/2016, on regulation on grid-connecting renewable energy–based mini grid
(Minister of Energy and Mineral Resources 2016a)

### 4.3 WHAT HAPPENED AFTER THE MAIN GRID ARRIVED?

Of the estimated 1,300 off-grid micro-hydropower projects in Indonesia, about 200 have experienced the arrival of the PLN grid. For these projects, four outcomes have been observed:

- **The mini grid was abandoned.** In an estimated 150 cases where the micro-hydropower did not function well (because of lack of proper management, for example) as a stand-alone system or the tariff was higher than PLN’s tariffs, the community abandoned the project and many village households became customers of PLN.

- **The mini grid continued to operate.** In about 50 cases where the micro-hydropower mini grid worked well and had a lower retail tariff than PLN, the community continued to operate it as a separate mini grid, with its own generation and distribution, while PLN provided electricity using a separate distribution line. Evidence from interviews suggests that whether customers decide to move to PLN lines or remain with the micro-hydropower mini grid depends on the relative quality of service.

- **All output was sold to PLN.** In five cases, the mini grid stopped providing retail service to the village and became a pure SPP that sold all of its generated electricity to PLN.

- **Only excess output was sold to PLN.** In four cases, the micro-hydropower plant continued to operate as a mini grid but sold all excess generation to the PLN for income generation.

The last two outcomes are examples of interconnection successes that Indonesian micro-hydro developers are working to advance.
Selling All Output to the Grid

Five micro-hydropower projects were converted to pure SPPs upon the arrival of the PLN grid (Tables 4.3 and 4.4). These projects had capacity of 13–730 kW. In all five cases, implementation of the off-grid components was funded by grants from international sources. Grid-connection equipment for the largest project was funded by a loan; the four other projects received funds from international sources under PSK Tersebar. The oldest project, Curugagung (Box 4.2), was completed under a regulation that preceded PSK Tersebar and inspired its drafting.

Three of the projects were owned by the village cooperative that had managed the micro-hydropower project when it was off-grid. The remaining two were privately owned, one by an individual from the village and the other by a micro-hydropower development company.

Box 4.2 Curugagung: Indonesia’s Pioneer Grid-Connected Micro-Hydropower Project

The owner of the Curugagung project invested all of his savings to develop an off-grid micro-hydropower project. Completed in 1991, with output of 13 kW, it sold electricity to the 121 households in the village.

Just three years after the project began operations, the PLN grid reached the village. The tariff of the mini grid could not compete with the tariff offered by PLN.

Upon the owners’ death, the NGO Yayasan Mandiri successfully lobbied the government to allow the project to interconnect with the PLN grid. Tariffs are low, but the income generated has been sufficient for financial viability.

This one-off arrangement prompted the finalization of PSK Tersebar, which later helped establish the more supportive 2009 regulations. The negotiated feed-in tariff is Rp 112 (about $0.008) per kWh, which yields about Rp 10.2 million ($755) a year assuming a capacity factor of 0.8. The plant is currently being rehabilitated.

Selling Only Excess Electricity to the Grid

Four micro-hydropower projects that were converted to SPPs sell only excess power to PLN (Tables 4.3 and 4.4 and Box 4.3). All four projects are owned by the village cooperative or association that established them and were interconnected to the PLN grid under PSK Tersebar. They range in capacity from 20 kW to 40 kW.
4.4 WHY HAVE SO FEW MICRO-HYDROPOWER PROJECTS BEEN CONVERTED TO SMALL POWER PRODUCERS?

Very few projects that have been converted to some form of SPPs. In contrast, 300–400 new micro-hydropower projects have started as on-grid facilities. One reason that so few micro-hydropower projects have become SPPs is that a portion of interconnection equipment costs are fixed. Other reasons have to do with restrictive regulations and policies.

Inability to Receive Permits

Indonesian law states that “grants of State/Regional Property shall be conducted with consideration for social, cultural, religious, humanitarian, noncommercial, and state/regional governmental purposes.”32 This law has been interpreted to mean that government-funded infrastructure cannot be used for private income generation. The government classifies SPPs as private or commercial income generation. As such it could provide permits for government-funded isolated micro-hydropower projects that would enable them to be converted to SPPs. Because most micro-hydropower projects implemented before 2009 were funded by the government (though the sources of the funds were international in some programs), most projects were blocked from receiving the required connection permit. For this reason, all of the projects in Tables 4.3 and 4.4 have private or foreign funding.

SPP developers argue that these government-funded micro-hydropower projects should be given permits to become SPPs, because PLN sales would be made on behalf of the village cooperative. In cooperative-owned SPPs, all of the income from sales to PLN supports social welfare services, such
as schools and clinics. Thanks in part to lobbying from SPP developers and micro-hydropower associations, grid connection of government funded micro-hydropower projects is now allowed, per Ministerial (MEMR) Decree No. 39/2017, passed in May 2017. It will be interesting to see whether this regulatory change leads to substantial increases in grid-connected mini grids in Indonesia.

**Inadequate Tariffs for Projects Interconnected before 2009**

Before the regulations introduced in 2009, all interconnections to the PLN grid were handled under the PSK Tersebar regulation, which stipulates feed-in tariffs based on the voltage type and location-specific generation costs of PLN. Developers have complained that the stated generation costs that PLN announced lacked transparency and were unreasonably low in some cases. As a result, few micro-hydropower projects became SPPs before 2009. The 2009 regulations did not allow SPPs established before 2009 to qualify for new feed-in-tariffs. Ministerial (MEMR) Decree No. 39/2017 specifies a 20-year power purchase agreement at tariffs of Rp 500 ($0.037) per kW for micro-hydropower.

**Expense of Complying with Post-2009 Regulations**

The 2009 and 2012 regulations provide higher feed-in tariffs, but they also require procedures that are complicated and expensive. For this reason, most cooperatives and NGOs continue to use PSK Tersebar, despite PSK Tersebar’s low tariffs and transparency shortcomings.

### 4.5 CONCLUDING OBSERVATIONS

When the grid arrived, most micro-hydropower projects in Indonesia were abandoned. But an important precedent was set in two important connection modalities: five projects connected as SPPs and sell electricity to the national grid, and four projects continued to sell electricity to retail customers and interconnected as SPPs to sell excess electricity to the national grid. These projects pioneered the regulatory environment and technical procedures, allowing others to follow in their footsteps.

Indonesia’s micro-hydropower sector is well positioned for grid interconnection in several ways:

- Indonesia pays feed-in tariffs to grid-connected projects that are, in theory, based on the geographically specific costs of electricity. These tariffs create economic niches in which grid-connecting formerly isolated micro-hydropower plants are profitable.

- Indonesia developed a sophisticated micro-hydropower industry over the course of two decades, thanks in part to long-running training programs supported by donors. Competition and local expertise reduce costs for good-quality installations. This pool of expertise includes spillovers from larger (MW-scale) hydropower projects built as independent power producers designed to be connected to the grid from the outset.

- A 2017 ministerial decree allows government-funded projects (by far the largest category of project) to interconnect and sell electricity back to PLN. The impacts of this decision have yet to be felt but are likely to increase the number of projects that survive the arrival of the grid through interconnection. Hurdles remain, however. Feed-in tariffs remain low. Low tariffs compound another key problem: financing. Donor grants have completely covered the interconnection costs of nearly all formerly isolated micro-hydropower mini grids that have
gone on to connect to the grid. For the sector to advance, developers and finance intuitions will need to work together to enhance the ability of financial institutions to evaluate the risk and profitability of these projects—and enhance developers’ ability to deliver projects with acceptable risk and returns. Financial institutions will need to offer financial products on terms that match the revenue stream and risk profile of these projects.
Table 4.3 Grid-Interconnected Mini Grid Projects in Indonesia that Started as Stand-Alone Projects, 1991–2006

<table>
<thead>
<tr>
<th>PROJECT NAME AND REGION</th>
<th>CURUGAGUNG, WEST JAVA</th>
<th>DOMPYONG, JAVA</th>
<th>SELOLIMAN (KALI MORON), JAVA</th>
<th>SANTONG, WEST LAMBOK</th>
<th>SELIDO-KECIL, WEST SUMATRA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Year of interconnection</td>
<td>1991</td>
<td>2003</td>
<td>2003</td>
<td>2004</td>
<td>2005/06</td>
</tr>
<tr>
<td>Pre-interconnect village load (kW)</td>
<td>12</td>
<td>10</td>
<td>30</td>
<td>15</td>
<td>730</td>
</tr>
<tr>
<td>Average monthly revenue</td>
<td>Rp 1.19 million ($88)</td>
<td>Rp 1.5 million ($110)</td>
<td>Rp 1.4 million ($100)</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Number of connections</td>
<td>121</td>
<td>40</td>
<td>45</td>
<td>—</td>
<td>20</td>
</tr>
<tr>
<td>Feed-in capacity (kW)</td>
<td>12</td>
<td>30</td>
<td>30</td>
<td>40</td>
<td>668</td>
</tr>
<tr>
<td>Tariff (per kWh)</td>
<td>Rp 112 ($0.008)</td>
<td>Rp 600 ($0.044)</td>
<td>Rp 533 ($0.04)</td>
<td>—</td>
<td>Rp 442 ($0.033)</td>
</tr>
<tr>
<td>Voltage</td>
<td>Low</td>
<td>Low</td>
<td>Medium</td>
<td>Low</td>
<td>Medium</td>
</tr>
<tr>
<td>Sells all kW or only excess?</td>
<td>All</td>
<td>Excess only</td>
<td>Excess only</td>
<td>Excess only</td>
<td>All</td>
</tr>
<tr>
<td>Costs of equipment to interconnect</td>
<td>Rp 90 million ($6,700)</td>
<td>Rp 55 million ($4,100)</td>
<td>RP 50 million ($3,700)</td>
<td>Rp 90 million ($6,700)</td>
<td>Rp 140 million ($10,400)</td>
</tr>
<tr>
<td>Funding source to interconnect</td>
<td>Loan</td>
<td>GTZ</td>
<td>GTZ</td>
<td>Local government</td>
<td>Equity and bank loan</td>
</tr>
<tr>
<td>Project owner</td>
<td>Cooperative</td>
<td>Cooperative</td>
<td>Village association</td>
<td>Village cooperative</td>
<td>Developer</td>
</tr>
<tr>
<td>Project facilitator</td>
<td>Yayasan Mandiri</td>
<td>ENTEC and Heksa</td>
<td>ENTEC and Heksa</td>
<td>Renerconsys</td>
<td>PT AMS</td>
</tr>
<tr>
<td>Annual Income generated from sales to PLN</td>
<td>Rp 10 million ($755)</td>
<td>—</td>
<td>Rp 68 million ($5,040)</td>
<td>—</td>
<td>Rp 2 billion ($148,000)</td>
</tr>
<tr>
<td>Uses of income from sales to PLN</td>
<td>Repay micro-hydropower investment</td>
<td>Fund cooperative activities</td>
<td>Fund second hydropower plant downstream from first</td>
<td>—</td>
<td>Owner discretion</td>
</tr>
</tbody>
</table>

Note: — Not available.
### Table 4.4 Grid-Interconnected Mini Grid Projects in Indonesia that Started as Stand-Alone Projects, 2008–13

<table>
<thead>
<tr>
<th>Project Name and Region</th>
<th>Wot Lemah MHP, Java</th>
<th>Krueng Kalla MHP, Aceh</th>
<th>Ciganas MHP, West Java</th>
<th>Bakuhau MHP, Sumba, NTT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Year of interconnection</td>
<td>2008</td>
<td>2010</td>
<td>2012</td>
<td>2013</td>
</tr>
<tr>
<td>Pre-interconnect village load (kW)</td>
<td>7.5</td>
<td>40</td>
<td>80</td>
<td>37</td>
</tr>
<tr>
<td>Average monthly revenue</td>
<td>Rp 0.9 million ($70)</td>
<td>Rp 4.24 million ($310)</td>
<td>Rp 4.7 million ($350)</td>
<td>Rp 2.2 million ($160)</td>
</tr>
<tr>
<td>Number of connections</td>
<td>25</td>
<td>222</td>
<td>485</td>
<td>305</td>
</tr>
<tr>
<td>Feed-in capacity (kW)</td>
<td>20</td>
<td>40</td>
<td>100</td>
<td>37</td>
</tr>
<tr>
<td>Tariff (per KWh)</td>
<td>Rp 533 ($0.04)</td>
<td>Rp 1,204 ($0.089)</td>
<td>Rp 656 per ($0.049)</td>
<td>Rp 525 ($0.039)</td>
</tr>
<tr>
<td>Voltage</td>
<td>Medium</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
</tr>
<tr>
<td>Sells all kW or only excess?</td>
<td>Excess only</td>
<td>All</td>
<td>All</td>
<td>All</td>
</tr>
<tr>
<td>Costs of equipment to interconnect</td>
<td>Used interconnection equipment in Seloliman (Kali Moron) project (see Table 4.3)</td>
<td>Rp 535 million ($40,000)</td>
<td>Rp 270 million ($20,000)</td>
<td>Rp 140 million ($10,400)</td>
</tr>
<tr>
<td>Funding source to inter-connect</td>
<td>Village, GIF, PLN</td>
<td>IBEKA</td>
<td>IBEKA</td>
<td>IBEKA</td>
</tr>
<tr>
<td>Project owner</td>
<td>Village association</td>
<td>Village cooperative</td>
<td>Village cooperative</td>
<td>Village cooperative</td>
</tr>
<tr>
<td>Project facilitator</td>
<td>PT GMN Renerconsys</td>
<td>IBEKA</td>
<td>IBEKA</td>
<td>IBEKA</td>
</tr>
<tr>
<td>Annual Income generated from sales to PLN</td>
<td>Rp 61 million ($4,520)</td>
<td>Rp 248 million ($18,400)</td>
<td>Rp 406 million ($30,000)</td>
<td>Rp 180 million ($13,300)</td>
</tr>
<tr>
<td>Uses of income from sales to PLN</td>
<td>Improve community livelihood</td>
<td>Provide micro loans, start small shops</td>
<td>Provide micro loans, start small shops</td>
<td>Provide micro loans for all households</td>
</tr>
</tbody>
</table>
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The experience of Cambodia, Sri Lanka, and Indonesia detailed in these case studies demonstrate several approaches for what happens when the national grid arrives in areas previously served by mini grids. They vary from interconnecting the mini grid generator to the main grid and selling electricity at wholesale to the national grid (small power purchasers [SPPs] in Sri Lanka and Indonesia) to transitioning to small power distributors (SPD) and abandoning generation (in Cambodia) to hybrid cases in which the mini grid both sells wholesale electricity and maintains its own distribution network to continue making retail sales in the village (SPP plus retail sales in Indonesia).

The cases indicate that various post-interconnection business models can be commercially viable. They are more likely to succeed when the following conditions are in place:

- Interconnection costs are not prohibitively high.
- Interconnection with formerly isolated mini grids does not present significant challenges in engineering or operations, because the mini grids were built to stringent technical standards.
- The isolated mini grid systems have access to additional sources of financing.

Analysis of the study countries reveals some possible patterns. As grid interconnection of formerly isolated mini grids becomes more common and understanding of them deepens, some of them may prove incorrect or be rendered meaningless as technology and other factors evolve. The emphasis or explanation for others may shift. Some may withstand the test of time.

### 5.1 WHEN THE GRID ARRIVES, COMMUNITY-OWNED MINI GRIDS GENERALLY STOP SELLING SELF-GENERATED ELECTRICITY DIRECTLY TO RETAIL CUSTOMERS

In most cases, when the main grid reaches a village that had been served by a community-owned mini grid, the mini grids stop selling self-generated electricity directly to retail customers. All of the community-owned hydro mini and micro grids in Sri Lanka and many (but not all) in Indonesia stopped serving households. In Cambodia, the outcome was different. Many private mini grid operators continued to sell to retail customers, but they did so as distribution entities that resell electricity generated by larger distant power plants owned by the main grid operator.

Three main factors explain why community-owned mini grids exit from retail supply business for: differences between the tariffs charged by the mini grid and main grid, differences in service levels, and various legal and financing barriers. Each factor is examined below.

#### Differences in Tariffs

National or main grid operators (usually government-owned enterprises) generally offer tariffs that are well below a mini grid’s cost of service. These tariffs are often artificially low because of highly
subsidized lifeline tariffs for low-consumption customers and politically mandated national uniform tariffs. A uniform national tariff reflects the government’s decision that customers in rural areas should pay the same for electricity as their urban brethren do, even if the cost of serving rural customers is much higher than the tariff charged. In addition, the overall tariffs of national utilities are often artificially low if the government provides general subsidies to government-owned utilities through the forgiveness of interest and principal payments and provides the government utility with the opportunity to purchase fuel at subsidized prices.

Indonesia is an exception. The tariffs for PLN’s rural customers on some remote islands, where PLN relies on diesel-fired generators, are often higher than the tariffs hydropower-based community-owned mini grids charge their members on the same islands. In about 50 cases, when the PLN grid reached villages on islands that would be served by PLN’s high-cost diesel generation, the community-owned mini grids continued to serve most members, because the mini grid’s prices were lower than PLN’s prices. In some instances, wealthier families migrated to PLN, because PLN was able to support larger household electrical loads, loads that could not be supplied by the capacity-constrained mini grid.

**Differences in Service Levels**

The national grid can generally power larger household loads during peak consumption periods. The mini grid’s electrical generating capacity is often sufficient in the first few years, before households acquire more and larger appliances. Once they do, customers are disappointed to find that they are unable to run them during peak evening hours, because too much electrical demand on the mini grid’s system will trigger blackouts and brownouts. If the national or regional grid operator is able to provide reliable service during peak hours, mini grid customers will probably switch over to the national utility.

However, the national utility may not be able to provide reliable service during peak hours for various reasons. In many developing countries, insufficient generating or transmission capacity is often a problem for larger national or regional government-owned utilities. The national or regional grid may be overtaxed or there is insufficient generating capacity connected to the grid, especially during the evening peak load. Although a government-owned utility offers 24/7 service on paper, its actual provided service often falls far short of that promise.

In India, the reason for unreliable service is different. India currently has a nationwide surplus of generating capacity, but many government-owned distribution utilities in individual states lack the money to pay for the electricity that could be generated. Consequently, Indian distribution utilities (referred to as discoms) often cut off the supply of electricity to their customers in connected rural villages during peak consumption hours. The cause of these cutoffs is financial rather than physical. Many Indian discoms lose money on the power they supply to rural customers. When they face overall shortages, they therefore usually cut them off first. Their unreliable service, especially during evening peak hours, when rural households most want electricity, creates opportunities for some mini grid suppliers (see the discussion of OMC Power in section 5.9).
Legal Issues

In Sri Lanka, legal issues restrict the mini grid’s retail sales when the grid arrives. The national utility (the Ceylon Electricity Board [CEB]) holds a legal monopoly on the right to sell electricity directly to retail customers. Isolated micro-hydropower mini grids were able to get around this restriction by registering as nonprofit Village Electricity Consumer Societies (VECS). The legal interpretation was that VECS do not sell electricity, but rather, self-supply electricity among dues-paying members.

There is also a legal restriction on wholesale sales of electricity by VECS. In order to interconnect and sell wholesale electricity to the CEB, VECSs must become cooperatives. As VECS they do not have the legal identity to enter into contracts; if they become cooperatives, they can sell to CEB under the standardized power purchase agreement contract. Few VECSs have pursued this legal option, because of difficulties in obtaining financing and the technical know-how to support this conversion.

Even if a VECS becomes a cooperative, it still needs financing to expand its generation capacity. And since it does not have a history as an SPP selling to the main grid, it would be difficult to obtain loans from commercial banks. Donor programs that provided grants to VECS are often no longer available.

One plausible alternative would be to form a joint venture with one of the private developers that has experience selling bulk power to the CEB. The private developer is likely to have easier access to and receive better terms on loans from commercial banks, because it has demonstrated experience in operating larger hydropower-based facilities. For a VECS (or a successor cooperative), the potential benefit of a joint venture is that it can access a steady stream of dividends from future bulk power sales. The dividends would provide a regular stream of income that could be used by individual households or the cooperative for projects that benefit the community as a whole.

To date no such joint ventures have been formed in Sri Lanka. In Indonesia and Thailand, joint ventures between communities and private developers have been blocked by well-intentioned laws that were designed to prevent private interests from benefiting from government grants that financed some portion of the initial community-owned installation. This barrier should not be insurmountable. Countries could require that grants be repaid to the government as a condition for a community to create a joint venture with a private company.

5.2 Few Isolated Community-Owned Mini Grids Have Become Small Power Producers

The fact that most isolated community-owned mini grids stop making retail sales does not necessarily mean that they will transition to grid-connected SPPs. In Indonesia, only 9 mini grids successfully made the transition with the arrival of the main grid; about 150 projects were abandoned. In Sri Lanka, of the more than 250 mini grids that were formerly isolated, only 3 connected to the main grid as SPPs; more than 100 were abandoned.
In both countries, the isolated mini grids were community owned. Whether the outcome would have been different if the mini grids had been privately owned or community-owned mini grids had been allowed to create joint ventures with private companies is not clear.

Whether or not a mini grid becomes an SPP seems to be highly dependent on the level of the feed-in tariff. Selling electricity to the national utility, where it is allowed, often means accepting a low feed-in tariff (typically the utility’s avoided generating cost from very large power plants). In Indonesia, for example, the formerly isolated 30 kW Seloliman micro-hydropower project sells electricity to the national utility at about $0.05 per kWh. The roughly $9,700 it earns annually barely covers operational expenses, taxes, land lease, and royalty payments for water usage.

5.3 Cambodia Bucked the Trend by Embracing the Transition from Mini Grid to Small Power Distributor

In most countries with community-owned mini grids, the arrival of the main grid has led to customers shifting over to the national utility. Cambodia’s experience has been different. Nearly 28 percent of Cambodia’s retail electricity is now sold through approximately 250 SPDs, most of which were previously isolated mini grids. This local private sector–led approach reflects three factors:

- the national utility’s lack of funds to and interest in investing in order to reach retail customers
- a proactive government and regulatory authority that worked with mini grid developers to upgrade distribution networks to utility standards before interconnection and adopted licensing and capital cost subsidy programs that help mini grids transition to SPDs
- the willingness of the national government to provide SPDs with ongoing operational subsidies as the quid pro quo for the requirement that they sell electricity to retail customers at a uniform standard national tariff that does not recover their costs.

5.4 Anti-Corruption and Investment Policies and Laws Thwart Interconnection

Laws and policies conceived to reduce corruption have sometimes had the unintended effect of blocking grid interconnection for community-owned mini grids. In Indonesia, the government reportedly does not give interconnection permits to projects built with government funds because of concerns that private operators would use village electricity infrastructure facilities paid for with government grants for private gain.

A similar phenomenon has been observed in Thailand, where community micro-hydropower projects were built as government–village joint ventures, in which villages provided labor and local materials and the government provided the mechanical and electrical hardware. This arrangement worked smoothly as long as the villages were isolated from the main grid. When the main grid arrived, these projects were abandoned rather than interconnected because of an anti-corruption law. Revenues from the sale of electricity to the national utility is prohibited under Thai anti-corruption regulations that ban the sale of
government assets to private interests and forbid government property from being used to produce revenues received by private groups (such as the village micro-hydropower cooperative or a joint venture between the village cooperative and a private operator) (Greacen 2010).

Clear and legal transfer of ownership from the government to the village cooperative upon commissioning would help, as would flexibility in interpreting corruption rules. For example, micro-hydropower projects built with government assistance should be allowed to interconnect to the main grid if they pay the government a royalty for use of government assets or reimburse the government for the grants it provided to construct the isolated mini grid. Such an arrangement could yield a “win-win” outcome: The government would receive some repayment for its earlier grants, and the villages would benefit from additional revenues through bulk sales to the main grid operator.

5.5 MINI GRID TECHNOLOGY, SCALE, AND HISTORY AFFECT INTERCONNECTION OUTCOMES

Technology, scale, and historical context all play important roles in determining outcomes when the main grid arrives to an area served by an isolated mini grid.

Technology

In the three case study countries, mini grids that connected to the main grid appear to fall into two major groups. The first includes hydropower mini grids that sell electricity to the national grid as SPPs (Sri Lanka and Indonesia). The second includes diesel mini grids in the hundreds of kW range that have hundreds or even thousands of customers that abandon their diesels and connect to the main grid as SPDs (Cambodia).

Local private sector actors (businesses or community cooperatives) are able to create value in both groups. In Indonesia and Sri Lanka, they did so by operating local hydropower plants as SPPs. In Cambodia, they did by maintaining the distribution system and coordinating sales to hundreds or thousands of small retail customers.

In Sri Lanka and Indonesia, hydropower has been able to survive the transition to a grid-connected business model even with low wholesale feed-in tariffs thanks to zero fuel costs; 24-hour electricity; long plant lifetimes; and technical, legal, and managerial assistance from nongovernmental organizations (NGOs). The absence of examples of grid interconnection of formerly isolated mini grids that use other generating technologies (solar, biomass gasifier) suggests that interconnection of non-hydropower mini grids is rarer—possibly because the higher generation cost of solar and biomass create additional hurdles that make an already marginal business proposition even less likely to work.

In Cambodia, hydropower mini grids are rare, because much of the country is flat. Isolated mini grids were powered mostly be relatively inexpensive diesel generators that used expensive fuel. In these cases, the distribution system ends up being the long-lived asset, with value that can be leveraged by experienced local mini grid operators in a post-connection environment.
Scale

Distribution franchisees in Cambodia serve an average of 2,300 customers. At scales substantially below this, the regulatory burden of overseeing multiple private sector actors is too high. In Indonesia, the scale of grid-connected projects is typically greater than 100 kW. In Sri Lanka, smaller projects have been connected, but they have been made possible largely through the dedicated efforts of the Energy Forum, an NGO for which commercial profitability has not been a high priority.

Country Context

In Cambodia, private diesel mini grids emerged mainly because for many years the government and national utility were incapable of providing service to many rural areas. Enterprising locals recognized that rural people were willing to more than $1 per kWh for mini grid electricity. Many of these local enterprises had unregulated prices because they came into existence before the national electricity regulator (the Electricity Authority of Cambodia [EAC]) was created, in 2002. The EAC took a light-handed approach to mini grid tariff regulation in its early years, focusing on incentivizing the mini grids to improve the quality of their distribution facilities through the “carrot” of longer license terms.

With the mini grid distribution infrastructure in place, it made sense to the government and the regulator, with assistance from the World Bank, to encourage mini grids to transition to distribution franchisees. Doing so allowed the utility to serve more people more quickly by focusing on medium-voltage lines, leaving the distribution side to experienced and nimble mini grid operators who knew their local communities well.

In Sri Lanka, micro-hydropower mini grids connected to the main grid resulted largely from efforts of the renewable energy NGO Energy Forum, which recognized that the plants had substantial life left. Without its actions, it is likely that all mini grids would have been abandoned with the arrival of the main grid.

In Indonesia, micro-hydropower was brought up to high technical levels of proficiency through long-term assistance from international development partners led by GIZ, in collaboration with Skat Consulting, Intermediate Technology Development Group (ITDG), and FAKT Consulting. Local counterparts developed skills in micro-hydropower design, construction, and operations and maintenance. These trained professionals soon developed collaborations with key ministries and utilities.

5.6 The Cost of Interconnection Depends on the Post-Connection Business Model

The different post-connection business models (SPD, SPP, or SPP + SPD) require different interconnection investments (Table 5.1).
Interconnections costs also vary by distance to the grid, the voltage level at which the interconnection will be made, and whether the equipment is domestically available.\textsuperscript{35}

The conversion to an SPD requires the lowest interconnection investment. Once distribution lines are upgraded to utility standards (which was required by the Cambodian regulator for a long-term mini grid license even before interconnection), interconnection is straightforward, requiring a step-down transformer, standard distribution switchgear, and a meter at the point of interconnection.

The conversion to an SPP or SPP + SPD requires the interconnecting of a generator to the national grid, which in turn requires the installation of relays that disconnect the generator in the event of a disturbance on the grid. The most complicated and most expensive are systems that have the ability to

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### Table 5.1 Equipment Requirements of Post-Interconnection Business Models

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Main grid purchases assets and takes over</th>
<th>Mini grid operator becomes a small power distributor (SPD)</th>
<th>Mini grid operator becomes a small power purchaser (SPP)</th>
<th>SPP and SPD (no islanding)\textsuperscript{a}</th>
<th>SPP and SPD (intentional islanding)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution grid to grid standards</td>
<td>✔</td>
<td>✔</td>
<td>✔</td>
<td>✔</td>
<td>✔</td>
</tr>
<tr>
<td>Transformer, distribution switchgear, and meter</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Relays supporting synchronous operation with the grid\textsuperscript{b,c}</td>
<td></td>
<td></td>
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<td></td>
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</tr>
<tr>
<td>Electronic load controller\textsuperscript{d}</td>
<td>Recommended</td>
<td>Recommended</td>
<td></td>
<td></td>
<td>✔</td>
</tr>
</tbody>
</table>

\textsuperscript{a} The appendix describes the technical requirements for the SPP & SPD cases (with and without islanding).

\textsuperscript{b} Generation sources such as photovoltaics that use grid-intertie inverters are simplest to interconnect, because their anti-islanding circuits are built in. Most micro-hydropower and biomass/biogas generators use some kind of rotating generation, in which electricity is generated by generators that rotate magnets past sets of copper wire coils. The simplest interconnection of rotating generation is for induction generators. It requires, at a minimum, relays with the following functions: American National Standards Institute (ANSI) device 81 (over/under frequency), ANSI 59/28 (over/under voltage), and ANSI 51 (overcurrent). Synchronous generators require ANSI 25 (sync check) in addition to the functions above. Three-phase generators may require neutral voltage displacement (59N) or zero sequence overvoltage relay (59G). Some utilities require additional relays, and developers may chose additional relays to provide further protection to their generators. For more information, see Greacen, Engel, and Quetchenbach (2013).

\textsuperscript{c} The cost of interconnection relays, step-up transformers, on-grid lines, and transaction meter equipment for the Kalimaron micro-hydropower project in Indonesia was about $6,000 (based on the 2003 exchange rate). An additional $750 was spent on technical tests to verify safety upon commissioning. See Budiono (2017).

\textsuperscript{d} An electronic load controller is an electronic device, generally used with micro-hydropower, that enables the mini grid to regulate its own frequency. Internal combustion engines (using fuel from biomass gasifiers, biogas, or diesel) typically use a governor to modulate fuel delivery to achieve the same function.
connect to the main grid and switch instantaneously to an island mode, providing back-up power to local customers. Innovation in grid-interconnection hardware for distributed generation is ongoing, suggesting that costs will fall over the next several years.

Distributed generators that connect to the main grid may also require engineering studies before interconnection. These studies typically cover load flow,\textsuperscript{36} short circuits,\textsuperscript{37} and protection coordination.\textsuperscript{38} All of these studies begin with a computer model of the existing electricity supply infrastructure (generation, transmission, and distribution) on the main grid and model the impact of adding a distributed generator. Taken together they can help accommodate safe incorporation of mini grids into the national grid and proactively address problems that might reduce the reliability of the grid. These studies can also be useful in preventing conditions under which the mini grid’s generator would have to disconnect from the main grid.

\textbf{5.7 Subsidies Are Needed to Cover Revenue Shortfalls}

A recent review of mini grids finds that “there is no country in Asia and Africa in which private sector investors have engaged in mini grid development where uniform national tariffs have been mandated” (Mathur 2017a). “Private sector (or community) investments in mini grids are most often made with (i) tariffs different from what the main grid levies and (ii) subsidies and/or soft loans.”

National electricity regulators use a variety of regulatory approaches in reviewing mini grid retail tariffs and allowing the tariffs to exceed the tariffs charged by the national or regional utility (Box 5.1). Whatever approach is used, mini grids need to at least cover their full operating costs if they are to survive. The minimum revenues can come from tariffs, subsidies, or both. If its tariff revenues are insufficient because of a mandatory uniform national tariff or some other tariff ceiling, the mini grid will need a subsidy to cover the shortfall or risk going out of business.
Box 5.1 Regulating Mini Grid Retail Tariffs: Three Countries, Three Approaches

**India.** India, which is often criticized for overregulation, has taken a light-handed approach to regulating mini grids. For the two major regulatory decisions—licensing and retail tariff-setting—it has opted for deregulation.

In Uttar Pradesh—the Indian state that has experienced the most private investment in mini grids—mini grids are not required to obtain licenses, and they do not need to apply to the state electricity regulator for approval of their retail tariffs. The legal standard for retail tariffs, which was established in the central government’s Electricity Act of 2003, is “mutual agreement” between the mini grid operator and customers—the functional equivalent of retail tariff deregulation. This hands-off approach is available only for mini grids that opt not to receive central or state government subsidies. If a mini grid operator chooses to receive a state or central government subsidy, its retail tariffs is capped—at levels most mini grid developers believe will be too low to achieve financial viability.

**Nigeria.** Like India, Nigeria has no uniform tariff requirement that caps mini grid tariffs. But unlike India, the Nigerian Electricity Regulatory Commission (NERC) regulates tariffs for mini grids with distribution capacity of more than 100 kW. Its stated goal is to provide operators with tariffs that reflect their own costs, constrained by specified targets for technical and commercial losses. NERC’s 2017 mini grid regulations provide a detailed multi-year tariff-setting formula to produce cost-reflective tariffs. Even with capital cost subsidies provided by the Rural Electrification Agency (REA), the tariffs are likely to be several times higher than the tariffs of nearby distribution companies. For mini grids with distribution capacity of less than 100 kW, NERC will accept tariffs that have been negotiated with the community. All 12 of the mini grids currently operating in Nigeria have capacity of less than 100 kW and are therefore not subject to ex ante tariff regulation by NERC.

These rules apply to unsolicited, bottom-up proposals from mini grid developers. It remains to be seen what tariff-setting approach NERC will adopt for mini grid projects that are winners of future competitive procurement by the REA. In other countries that have attempted top-down, competitive procurements of mini grids, requests for proposals often specify a tariff ceiling and a minimum number of required connections and then seek bids on the minimum capital cost subsidy sought by the bidder. Hence, with top-down competitive bidding, tariff regulation takes the form of a before the fact general tariff ceiling rather than an after the fact review of the costs of individual mini-grids.

**Rwanda.** Like Nigeria, Rwanda requires cost-reflective tariffs. Its regulations provide general guidance on the components that are to be included in calculating allowed costs, the sum of which is referred to as “required revenues.”

A mini grid developer need not obtain the regulator’s approval of its cost calculations before its retail tariffs go into effect. But the regulator reserves the right to review the developer’s cost calculations at any time. Rwanda’s regulations explicitly recognize that the tariffs charged by mini grids are likely to be higher than the tariffs charged by the main grid, stating that the fact they are higher will not be considered a valid basis for complaint.
The need for ongoing operational subsidies has been recognized in Cambodia. Distribution franchisees are required to charge CR 800 ($0.20) per kWh for most customers, CR 480 ($0.12) per kWh for the water pumping and very small residential customers. A subsidy from a fund capitalized by the national utility covers the difference between this tariff and the distribution franchisee’s costs. Cambodia’s willingness to provide operating subsidies is very much the exception.

In general, national governments are willing to provide upfront capital cost subsidies (often provided by donors) to private operators (as they do in Bangladesh, Cambodia, Mali, Nepal, and Tanzania) but not operating cost subsidies. In contrast, government-owned utilities in these countries may be receiving very large subsidies for rural electrification, through both their main grid extensions and their own mini grid operations. Subsidies and cross-subsidies for the government-owned national utility tend to be hidden from view, making them politically more acceptable. In both Kenya and Tanzania, for example, the 15–20 government-owned mini grids are required to charge a national uniform tariff to their customers, even though the actual costs of running the mini grid are much higher. The shortfall between the tariffs the government-owned mini grids charge and their actual costs are paid for by other customers. The shortfall is recovered as an allowed cost that is usually buried deep within their general tariff request. It would be harder to provide the same subsidy to a private mini grid operator, because the subsidy payments would be more visible.

Withholding subsidies from private sector mini grid enterprises seems shortsighted. Countries that allow subsidies to private mini grids recognize that mini grids can provide valuable services regardless of ownership and that safeguards can be put in place so that the public gets its money’s worth from public funds invested in privately owned mini grid projects. Thought has to go into designing the subsidy mechanism so that public interest is upheld, and verification and enforcement are required. But these efforts are worth making, as they create conditions that substantially broaden the pipeline of good projects.

### 5.8 MINI GRIDS VERSUS THE MAIN GRID: A FALSE DICHOTOMY?

The prevailing mindset (especially in Africa) is that mini grids and main grid extensions are two separate and mutually exclusive paths to scaling up rural access. Under this view of the world, only one of the two approaches can be workable in a village at any given time.

The three case studies provide evidence that the “competing alternatives” view of the world is an overly simplistic and unproductive way to think about scaling up access. Mini grids and the main grid can complement each other. Once the physical interconnection takes place, different buy and sell transactions between the two delivery technologies can lead to more reliable and less expensive electricity for consumers.

The existence of a physical interconnection between the main grid and a mini grid can accommodate a variety of business models, including:

- a pure SPP, which exports all of its production to the main grid
- an SPP + retail supplier that exports to and imports from the main grid
• a pure SPD, which imports all of its electricity from the main grid.

Each of these business outcomes can lead to “win-win-win” outcomes for the mini grid operator, the main grid operator, and their customers. But none of them will happen automatically. It is the job of the regulator and policy makers to create a framework that will allow for different business outcomes, as it is not yet clear which outcome is best. Moreover, it is unlikely that one outcome will always be best in every situation. The best strategy is to develop frameworks that will allow efficient business outcomes to emerge in individual cases.

Government officials and donors have a tendency to think in terms of two competing solutions—the main grid solution and the mini grid solution—because they often think in terms of the provision of infrastructure. When the world is viewed in this way, it seems logical that access will be provided by either the main grid operator or the mini grid developer but not both. But true energy access is better defined as sustained and reliable provision of electricity at some specified service level rather than simply the “mere existence of poles, wire and even a household grid connection” (Okapi Research and Advisory Services 2017, 20). The next frontier in rural access scale-up in Africa and Asia will be to examine how mini grids connected to the main grid can jointly provide a more reliable and less costly level of service than either operating separately.40

5.9 Why do consumers sometimes choose the higher-priced electricity supplier?

If two electricity suppliers offer essentially the same service, economic theory indicates that consumers will choose the supplier that offers the lower price. But suppliers often offer services that are not identical. If they offer similar services, it may sometimes appear as if consumers are incorrectly choosing the higher-priced supplier.

In the Indian state of Uttar Pradesh, OMC, India’s largest private mini grid provider, serves customers in more than 75 rural villages. UPPCL, the state government-owned distribution enterprise, is already operating in many of the villages where OMC has built mini grids.

OMC sells electricity to its residential customers on a prepaid monthly lump-sum basis. Residential consumers who take OMC’s basic package of two LED lights and one phone charger for six hours a day pay an effective kWh price of $0.8–$1.3 per kWh — considerably more than the $0.05 per kWh (estimated for 2017–18) charged by UPPCL for its metered residential customers.41 Despite the large price difference, OMC has been successful in signing up existing UPPCL customers.

Why would a residential consumer choose the higher-priced OMC service? The short answer is that OMC and UPPCL are not providing the same service. OMC guarantees the availability of its service during the important evening peak hours, when UPPCL service is often sporadic. The
fact that so many customers of UPPCL were willing to sign up with OMC at a higher charge shows that rural households are willing to pay a premium for reliable service.42

OMC and UPPCL are engaged in direct retail competition. Such competition is now common in the United States and most European countries. However, there is a big difference between retail competition there and retail competition in Uttar Pradesh. In OECD countries, retail suppliers do not build separate distribution systems; they usually compete to supply consumers over distribution lines owned and operated by a neutral distribution company. In contrast, in Uttar Pradesh OMC and UPPCL operate their own separate distribution systems in the same villages. In some areas, each side of the street has a separate set of lines.

This duplicative distribution system creates a problem for donor organizations that might want to fund OMC-like initiatives. The governing boards of international and bilateral donor organizations would find it politically difficult to justify financing investments in a new privately owned distribution system if the government-owned discom already has a distribution network in place. But the private company would be understandably reluctant to deliver its electricity and guarantee the reliability of its supply if it is forced to use the sometimes unreliable and poorly maintained distribution system of the government discom. The question then whether it is commercially and physically feasible to require UPPCL and OMC to use the same set of distribution lines to compete for retail customers, the norm in OECD countries. In this case, it does not appear to be so.

5.10 Invigorating Investment by Proactively Developing Regulatory Frameworks

In all three of the study cases, when communities (Indonesia and Sri Lanka) and local private developers (Cambodia) made their investments in isolated mini grids, there were no specific rules or policies in place to inform them as to what their options would be when the main grid reached their villages. These communities and small local entrepreneurs built mini grids because their communities needed electricity, and there was no other option. As the grid expanded, and with lobbying from NGOs and concerned communities, the institutions that wrote and enforced rules in the power sector in Cambodia, Sri Lanka, and Indonesia made changes to accommodate integration of mini grids and the main grid.

This approach of creating policies and regulations as the need arises is not likely to continue to work for governments in Africa and Asia that are serious about encouraging private investors to build hundreds and thousands of new mini grids. Private investors, especially large national and international companies, will not be willing to make major investments in mini grids if there is no policy and regulatory clarity as to what prices they will be allowed to charge and what their post-interconnection business options will be. Without more certainty, private investment in mini grids will be too risky. And the cost of continuing regulatory and policy uncertainty will be the loss of major private investments that could otherwise lead to a significant scale-up of grid quality electricity in rural communities.
In recent years, Africa and Asia have adopted promising regulatory policies. In Nigeria, Rwanda, and Tanzania, the national electricity regulators issued detailed rules and regulations for mini grid projects. Draft mini grid rules are expected soon in Kenya. The Indian state of Uttar Pradesh issued a mini grid policy statement and supporting regulations in 2016. Similar initiatives are under way to introduce mini grid policies and regulations in other Indian states (Bihar and Jammu and Kashmir).

In both Africa and Asia, national mini grid policies are being buttressed with what might be termed regulatory contracts. For example, the mini grid rules issued by Nigeria’s national electricity regulator include model agreements between communities and mini grid developers. These agreements lay out the specific terms of service (hours, quality) and the tariffs that will be charged. In Myanmar (where the national electricity law does not deal directly deal with mini grids), a model trilateral agreement has been drafted that lays out the rights and responsibilities of the village, the private developer, and the government agency that will give grants to the mini grid.

These initiatives can be broadly described as “regulation by contract.” A regulatory contract can supplement the traditional regulatory approach of relying on the case-by-case application of general principles or standards in mini grid rules or laws. A regulatory contract typically goes into more detail than is possible in a national mini grid regulatory framework. Regulatory contracts also have the advantage of gaining formal buy-in from a level of government that may be closer than the national regulator to the consumers the mini grid will serve. This buy-in is especially valuable if a mini grid will be charging retail prices that are higher than the tariffs charged by the government-owned utility.

Regulatory contracts are a relatively new phenomenon for mini grids. There are precedents in electricity privatization, however. In the late 1990s and early 2000s regulation by contract was used in privatizations of large electric distribution system in Albania and Uganda. In both instances, the contracts were backed up by partial risk guarantee instruments to bolster compliance (Bakovic, Tenenbaum, and Woolf 2003).

It would be naïve to believe that regulatory contracts by themselves constitute a magic bullet that will work in all circumstances. Private developers still need to decide whether the project’s underlying economics make commercial sense. To paraphrase one private mini grid developer: “If the numbers do not compute, then the contract is just a lot of words on pieces of paper.”

5.11 Emerging Developments Affecting Mini Grids

The case studies focused on mini grid projects developed either by local community organizations (Sri Lanka and Indonesia), often heavily assisted by NGOs or governmental entities, or by small local entrepreneurs (Cambodia), with limited access to formal channels of finance. These projects often benefited from large donor or government grants and relied on generating technologies that have been in use for years. These mini grids might be described as second-generation mini grids (Box 5.1).
The Emergence of Third-Generation Mini Grids

New developers

Many large international and national private companies are taking initial steps to develop mini grid projects. International electrical equipment supply companies like Caterpillar, Tesla, Siemens, General Electric, ABB, and others have publicly announced that they intend to enter the mini grid market. It is still unclear whether they will limit themselves to supplying equipment or they will also take on operational and ownership responsibilities. These companies are building pilot projects with new modular technologies (usually solar PV with some backup or storage system) in a number of developing countries. These large private companies are presumably motivated by the potential to build hundreds of installations using their proprietary technologies. By building at hundreds of modular systems, there will be opportunities for cost reducing economies of scale that were not second-generation developers. Unlike second-generation local private entrepreneurs, these new third-generation companies will have ready access to national and international financial markets.

New technologies

Second-generation mini grid developers almost always used standard existing technologies (mini-hydropower and diesel generation). They typically charge customers flat monthly tariffs or postpaid tariffs, relying on basic meters, on-site meter reading, and in-person collections.
Third-generation developers use sophisticated hybrid generating technologies, such as modular solar photovoltaics combined with batteries and diesel generation and optimized with state-of-the-art control systems. They use prepaid payment systems similar to those used for mobile phones and some solar home system systems in Africa. Third-generation mini grids also make use of cellular data networks to allow remote monitoring of the generation system, so that engineers can spot problems as they start to emerge and make adjustments or repairs before small problems cascade into larger ones. Some third-generation mini grid developers make use of sophisticated load dispatch technologies to ensure that priority loads always get electricity by automatically shifting low-priority loads to times of energy surplus.

**Public-Private Partnerships for Mini Grids**

Historically, ownership of mini grid systems has been pure private, pure community, or pure national utility. But hybrid business models are now emerging. In Ghana, Kenya and Mozambique, for example, both governments and private companies have expressed interest in public-private partnerships. These partnerships can take various forms:

- The private company could build, own, and operate multiple mini grids, which would be sold to the national utility after six to eight years, with the private company continuing to operate the generation and distribution components of the mini grid for the national utility.

- The private company could build and operate the generation facilities and sell all of its output to the national utility (usually partially or totally owned by the government) under contract. The national utility or state government would own and operate the distribution system or only the mini grid distribution system, contracting with the developer or a third party to operate the distribution systems. The mini grid’s customers would be customers of the national utility (World Bank 2017).

- The private company could build the mini grid, sell it to the national utility upon completion, and then lease it back from the national utility for some defined period of time (Mathur 2017b).

These joint public-private arrangements have at least two potential advantages. First, the options for what happens if the main grid arrives can be specified in detail in the contract between the mini grid owner/operator and the national utility rather than subject to the application of general regulatory rules.

Second, if the private operator requires subsidies, they can probably be delivered more reliably and with less political opposition through contractual payments from the national utility to the mini grid owner/operator. Such an arrangement avoids the need to create a new separate government-run subsidy programs to channel subsidy payments to the private operator.

**Mini Grids Connected to the Main Grid**

Most mini grids in developing countries are built as separate isolated systems in rural areas that are not connected to the main grid. In contrast, mini and micro grids being developed in the United States and other developed countries are typically connected to the main grid from the outset. They were never
planned to operate in an isolated mode, except when the main grid goes down, for weather or other reasons.

As the main grid expands and reaches previously unconnected mini grids in developing countries, it is important to explore how these previously autonomous “energy islands” can operate in grid-integrated mode, as proposed in Kenya and discussed in India. The new mini grid regulations in Nigeria explicitly provide for interconnected mini grids. Most knowledgeable observers believe that grid-integrated mini and micro grids will be the dominant future global model. It therefore makes sense to explore how such mini grids could be promoted in developing countries.

5.12 RECOMMENDATIONS

Several policy recommendations and recommendations for future research emerge from the analysis. Policy recommendations include the following:

- Create a regulatory and policy framework that allows for mini grids to operate both as stand-alone systems and integrated with the national grid. Such a framework would reduce the commercial risk that mini grid developers face in building isolated systems. The regulatory roadmap should detail all business options available to the mini grid developer when the main grid eventually connects to a previously electrically separate mini grid.

- Offer a range of post-interconnection business options for what happens “when the big grid reaches the little grid.” Options should include continuing business as SPPs, becoming SPDs, and buying electricity from and selling it to the main grid operator and other entities connected to the main grid (retail plus SPP).\(^43\)

- Create rules that specify how mini grid developers will be compensated for their assets in the event that the main grid arrives and the mini grid operator shuts down its business. Consider whether the mini grid operator’s work in “pre-electrifying” the area merits compensation in addition to compensation for its assets.

- Streamline regulatory processes and requirements so that licensing, permission to interconnect to the main grid operator, retail tariff-setting, and other business and environmental approvals are integrated and duplication of bureaucratic processes minimized. Establish lighter requirements for smaller mini grids.

- Offer umbrella licenses, permits, and registrations for mini grid developers that use the same generating and distribution technologies at multiple sites.

- Specify the conditions under which mini grids should be built to grid-ready standards and the conditions under which less costly “skinny-grids” should be allowed.

- Eliminate prohibitions that prevent mini grids originally built as government-funded isolated projects from connecting to the main grid, possibly by allowing government contributions to the original isolated mini grid assets to be repaid over time using a portion of revenues from electricity sales to the main grid.

- Remove legal and regulatory barriers that prevent communities from entering into joint ventures with private developers for new or expanded mini grids, whether isolated from or connected to the main grid.
• Create subsidy parity. If capital and operating subsidies are currently provided to the main grid owner for grid extension and for operating mini grids, provide comparable subsidies to private mini grid operators operating in joint ventures or independently so that the playing field is level.

These recommendations are not new. National or state-level regulators in India, Nigeria, Rwanda, and Tanzania have already implemented variants of them. In the first quarter of 2018, the Global Facility on Mini Grids will issue a six-country study (of Bangladesh, Cambodia, India, Kenya, Nigeria, and Tanzania) that will compare and contrast how regulators have dealt with these and other regulatory issues.

In light of the limited scope of this study, and the likely emergence of third-generation mini grids, further research or pilots with a strong operational focus should be undertaken. These pilots and studies could:

• Examine how mini grids can be connected (in islanded and non-islanded mode) to the main grid from Day 1 of operations (as proposed by PowerGen in Kenya and in the recently issued Nigerian mini grid regulations).44

• Analyze the commercial, technical, and regulatory issues in interconnecting solar hybrid and biomass mini grids to the main grid.

• Describe and analyze hybrid operational and ownership models in which both the national utility and a private operator form a public-private partnership to build and operate new mini grids (as planned for 14 northern counties in Kenya and proposed in Madagascar). Evaluate the contractual arrangements needed for each of the public-private partnership models.

• Provide estimates of the magnitudes of three types of subsidies in countries that are pursuing mini grids and main grid extension:
  - general subsidies to publicly owned national and regional entities that provide distribution service
  - specific subsidies to publicly owned national and regional distribution entities that connect new rural customers by extending the main grid
  - specific subsidies to publicly owned national and regional entities that own and operate isolated mini grids.

• Develop a cross-country database on the “hard” and “soft” costs of interconnection as they vary by technology, distance to the main grid, interconnection voltage levels, and the functions performed by the mini grid.

• Create a spreadsheet template that can be used to calculate the costs and revenues of interconnecting previously isolated mini grids from the commercial perspectives of the mini grid owner and the main utility owner.

• Develop a user-friendly platform where mini grid developers can provide data on operations and capital and operating costs using a standardized template to seek financing from potential investors (Brent 2017).

• Develop a primer for non-engineers on the engineering aspects of interconnection and different levels of islanding.
REFERENCES


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APPENDIX TECHNICAL PRIMER ON MAIN GRID–CONNECTED MINI GRIDS

In some locales, mini grids are permitted to sell electricity to households and the main grid. This appendix describes the technical requirements they must meet to do so.

STAND-ALONE OPERATIONS

Selling electricity to the main grid (whether or not the mini grid is simultaneously supplying its own customers) requires two key changes to a mini grid that had been operating in a stand-alone fashion. The first has to do with control of frequency—literally how rapidly the generator is spinning and thus how quickly the electricity is alternating. When the village needs more electricity, the generator in a stand-alone mini grid needs to ramp up power production; when the village needs less electricity, it needs to reduce power production. Failing to match supply and demand results in generators spinning either too slowly or too rapidly, producing electricity with frequency that is too low (when demand exceeds supply) or too high (when supply exceeds demand). Either can result in burned-out appliances and/or burned-out generator parts.

Stand-alone fossil fuel generators like diesel generators match supply and demand by automatically modulating the amount of fuel sent to the engine through a governor that controls fuel injection or the engine’s carburetor. More fuel means more power, enabling the generator to keep on spinning at rated speed even as the generator demands more torque, like a bicyclist exerting more effort to maintain speed going up a hill.

Small hydropower mini grids use a similar technique. An automatic regulator device carefully closes or opens the penstock valve little by little in response to real-time changes in electricity demand. Most plants below 100 kW opt for a solution that is simpler to implement because it requires no moving parts. A circuit called an electronic load controller diverts a portion of the electricity to a ballast load (a heater) to be “thrown away”—literally burning up any excess electricity as heat. This discarded electricity is adjusted many times a second in order to keep the generator spinning at the correct speed in the face of varying loads. A bicycle analogy would be the (exhausting) practice of pedaling at full power all the time but keeping the speed constant by applying the brakes—sometimes more, sometimes less depending on the terrain.

MINI GRIDS CONNECTED TO THE MAIN GRID

When a mini grid’s generator connects to the national grid, it no longer needs to vary its power production in response to demand; the national grid is able to absorb all of the electricity provided to it by the mini grid generator. The mini grid generator’s contribution is miniscule in comparison to the main grid’s generators. Somewhere in the national grid’s large collection of interconnected generators, the function of balancing supply and demand is accomplished—typically by large fossil fuel or hydropower
generators that are dispatched as needed by the system controller, at least one of which is always operating in a “load-following” mode, modulating fuel or water supply in real time as necessary.

The first change that is needed to transition from stand-alone to grid-connected mode is thus to switch from a mode in which the generator controls the frequency to one in which the generator power output is constant. In the case of a micro-hydropower plant with an electronic load controller, the electronic load controller is turned off in grid-connected mode. There is no need to waste any excess, as the grid can absorb it all.

The second change that is needed is the addition of protection relays that monitor the voltage and frequency of the main grid and monitor the power flowing from the mini grid to the main grid. If anything is sufficiently abnormal, these relays disconnect the small distributed generator, to protect both it and the main grid. One of these relays also handles the tricky business of waiting until the moment when the generator’s frequency and phase are in perfect lockstep with the grid before closing the switch that connects the two during initial start-up or any reconnection following a disconnection.

The way the generator regulates voltage may also need to change, depending on the requirements of the utility. When operating as a stand-alone mini grid, the generator’s automatic voltage regulator is set to keep voltage constant. The national utility may prefer a different setting—for example, one in which power factor is constant, which may be useful in enhancing the utility’s ability to control voltage in different nodes in proximity to the distributed generator. (A full explanation is beyond the scope of this appendix.)

**Selling to Both Main Grid and Mini Grid Customers**

What are the requirements of a system that supplies power to village households and sells excess electricity to the main grid? The simplest case is one in which the village load never exceeds the generator’s capacity, and power is always flowing out of the mini grid to the national grid. By contractual arrangement, this is the situation in the Indonesian case study described in this report.

To understand what is going on, conceptualize the mini grid and its connected retail customers as a single electrical entity, with the mini grid bundle connected to the national grid through an electrical meter at a single point. Sometimes (e.g., in the middle of the night) this entity produces more electricity for the national grid, because villagers are asleep and using less power. At other times (e.g., in the evening when the village is using lights and watching TV), the mini grid produces less electricity for the grid. From the national grid’s perspective, the mini grid looks like a generator that ramps up and down. The grid absorbs whatever is provided, because overall balancing of supply demand is accomplished elsewhere in the national grid. Because the national grid is establishing frequency, power flow out of the mini grid system is always inherently simply the excess—nothing more, nothing less.

**Selling to and Buying from the Main Grid**

In the more complicated situation in which power flows in to or from the mini grid, the main grid experiences the mini grid sometimes as a power source (the curved black arrow in *Error! Reference source not found.*) and sometimes as a load (the hollow arrow). In this case, the utility typically requires
a more complicated metering arrangement, because it (justifiably) may want to charge more for the back-up electricity it supplies than it charges for the varying amounts of electricity the mini grid injects into the main grid.

**Figure A.1: Schematic of Mini Grid Supplying Electricity to Its Own Customers and Selling Excess to the National Grid**

The situation gets trickier still if the mini grid wishes to maintain the ability to continue serving its customers in the event the main grid suddenly shuts off. This situation—called “intentional islanding”—requires instantly disconnecting from the de-energized national grid and turning on the electronic load controller (in the case of micro-hydropower) or the speed governor (in the case of an internal combustion engine) to perform the function of frequency control that the grid had been providing while interconnected.\(^46\) Utilities are more anxious about islanding, because substantial safety hazards arise if lines are energized by the mini grid when utility workers think the lines are de-energized. Examples of mini grids with intentional islanding capability are not uncommon.\(^47\) The practice is likely to become more common as deployment of mini grids, and their interface with often intermittent national grids, expands.
ADVANCED MICROGRIDS: THE NEXT GENERATION

The ability to intentionally island is one step toward a future that micro grid engineers in the United States and Europe are developing. In developing countries, a basic mini grid connected to the main grid is able to island and reconnect (synchronize with the main grid). More capabilities will be added over time. Advanced micro grids will include controllers that will be capable of sensing main grid conditions, monitoring and controlling the operation of a micro grid and its loads to maintain electricity delivery to critical loads during all operating modes (grid-connected, islanded, and transition between the two) (see Venkata and Shahidehpour 2017 and Sandia National Laboratories 2014). Further refinements include the ability to connect mini grids to form regionally networked micro grids and automating the ability of mini grids to provide energy and ancillary services (such as reactive power). If incentivized and coordinated, all of these refinements can enhance the operational performance, reliability, security, and economics of both micro grids and the main grid.

REFERENCES


Notes

1. There is no universally accepted definition of a mini grid. This report defines it as a low-voltage distribution grid that is supplied with electricity from one or more small generators (usually renewable) that supply electricity to a target group of consumers, typically including households, businesses, and public institutions. A mini grid may be electrically connected or electrically isolated from the main grid. A mini grid that is connected to the main grid may have the ability to island (that is, separate) its operations from the electrical system of the main grid.
2. In developed countries with 100 percent electrification, micro-grids (the more common term in developed countries) are typically connected to the main or macro-grid from the outset. The principal motivation for micro-grids has been to enhance reliability in the case of extreme weather events. Regulators and policy makers in at least three states in the United States (California, Minnesota, and New York) are considering proposals to expand the roles of micro-grids by allowing them to also buy and sell electricity in regional bulk power markets (see, for example, New York State’s “Reforming the Energy Vision” [https://rev.ny.gov]).
3. A 2001 survey of 45 rural electricity enterprises by Enterprise Development Cambodia found that most charged $0.40–$0.70 per kWh. The Electricity Authority of Cambodia 2016 lists approved diesel mini grid tariffs as high as CR 4,100 ($1) per kWh.
4. The Multi-Tier Framework describes tiers of service based on key service characteristics, including the ability to avail energy that is adequate, available when needed, reliable, of good quality, convenient, affordable, legal, healthy, and safe for all required energy services. Tier 2 powers general lighting and television, providing less than 200 W per customer, with hours of service that are limited to a few hours a day (for details, see Bhata and others 2013).
5. The maximum distance a low-voltage distribution line can be extended depends on the load served, the gauge (thickness) and material type of the low-voltage wire, and whether the circuit is three-phase or single. Low-voltage lines are typically no more than 1 kilometer long.
6. The heavy workload may be a consequence of the EAC’s intense regulatory oversight of mini grids, which involves inspections and frequent reviews of reports and detailed tariff calculations.
7. In addition to standardizing tariffs of distribution franchisees connected to the national grid, the initiative also reduced tariffs for customers of EdC connected to the national grid.
8. Peru uses a similar cross-subsidy scheme for customers of isolated mini grids (see Tenenbaum and others 2013). One difference is that the subsidy scheme in Peru is administered by the national electricity regulator rather than a national or regional government-owned utility. Tanzania proposed a different approach. In its 2015 mini grid rules, the national electricity regulator (EWURA) required that the national utility (TANESCO) supply bulk power to distribution licensees at a discounted (non-cost-recovering) wholesale tariff. The expectation was that this subsidy to SPDs in their bulk supply purchase price would be paid for by TANESCO’s other customers. In EWURA’s 2017 mini grid rules, this proposed subsidy was eliminated from the rules; it was not replaced by any other subsidy mechanism.
9. Two key implementation issues arise in making these calculations. First, the EAC makes 250 separate cost of service calculations, one for each distribution franchisee. The submitted numbers must be audited at least on a spot basis. Second, the EAC must make a decision about the level of line losses on the mini grid’s lower-voltage (LV) distribution lines it will use in making the cost of service calculation. The EAC has decided not to automatically accept the LV losses reported by individual mini grids. Instead, it uses a benchmarked value for LV losses. If an individual distribution franchisee can achieve LV losses that are lower than the benchmarked value, it will earn more money. If its LV line losses are higher than the benchmarked value, it will earn less money. LV line losses for distribution franchisees were recently at about 15 percent. The figure represents an improvement from about 20 percent in 2005, but it is still higher than the 4–5 percent losses achieved by EdC on its LV lines.
11. For a description of a similar subsidy mechanism in Peru, see Revolo (2009).
12. The Nigerian electricity regulator recently adopted a standardized spreadsheet with a multiyear tariff-setting system for isolated mini grids. It eliminates the need to come back to the regulator for approval of new tariffs whenever there is a significant change in costs (see annex 15 in the Nigerian Electricity Regulatory Commission’s regulations for mini grids).
13. Table 18 in the EAC’s 2014 annual report shows all wholesale tariffs to distribution franchisees.
14. As of 2014, 241 distribution franchisees were distributing and reselling EdC electricity to 686,308 customers (see annex 5B of the EAC’s 2014 annual report).
15. A subsidy of $45 per connection is low compared with connection subsidies in other countries. Mali and Tanzania subsidize rural household connections at ten times this rate or higher.
16. The term pico hydro refers to systems up to 10 kW of installed generating capacity. Micro-hydro systems installed generating capacity of 10 kW–100 kW. Mini-hydro systems have installed generating capacity of 100 kW–10 MW.
17. In contrast, the privately owned mini-hydropower projects (each 10 MW or less) selling to CEB created more than 240 MW of installed generating capacity by the end of 2011.
18. For information on the World Bank’s involvement, see World Bank (2012).
19. The $16,900 refers to the cash funding required for the project. In addition, villagers were required to provide about 10 percent of the project’s costs in labor and materials (see Subasinghe 2016).

20. Privately owned SPP projects were able to get better loan terms than VECS. In 2010 the typical loan term for a privately owned SPP appears to have been an 8-year loan with a 13 percent interest rate and a 1.5-year grace period. Loans to VECS were perceived as riskier, because they were repaid out of the household savings on energy purchases relative to their preconnection payment. In contrast, private operators were guaranteed a 20-year revenue stream for their electricity sales to CEB.

21. There were some exceptions. Initially, many VECS set their monthly fees high enough to fund sinking or reserve funds, which would be used to pay for major repairs. Over time, however, many VECS found it difficult to persuade their members to continue contributing to these funds.

22. For example, an in-depth survey of mini- and micro-hydro projects [MHPs] in Nepal concluded that “tariffs are set to just recover the operating costs and sometime even just the salary costs. To meet the costs of major repairs, users are asked to contribute additional sums. The tariffs are also lower because having contributed in cash and/or kind for the construction of the MHPs, the communities are unwilling to pay higher tariffs reflecting the real costs” (Kumar and others 2015, 42).

23. Some of the poles and wires of the distribution system were reportedly salvaged for use elsewhere, but the equipment within the generation powerhouse was left to rot and rust (communication with Wathsala Herala, Energy Forum, October 28, 2017).

24. In 2015 CEB’s average cost of supply at the rural household level was about $0.15.

25. Even after adding in the fixed charges paid by CEB’s retail customers in the first three blocks of monthly consumption (0–30, 31–60, and 61–90 kWh), the per unit cost is still considerably lower than the roughly $0.25 per kWh the VECS charged. For example, a customer consuming 30 kWh a month would pay $0.017 per kWh plus $0.067 per kWh in fixed charges per kWh or $0.0237 per kWh versus $0.025 per kWh if the same volume of electricity were acquired from the VECS.

26. In contrast, the average number of customers served by SPDs in Cambodia is 2,600.

27. In its 2015 second-generation mini grid rules, Tanzania’s national electricity regulator (EWURA) mandated that the national utility sell electricity to SPDs at subsidized bulk supply tariffs. This requirement was eliminated in the third-generation rules, issued in June 2017.

28. The SEA has reportedly decided to streamline the process for VECS that wish to operate SPPs by requiring just an energy permit application. The rationale for streamlining is presumably that the hydropower facility is already established and operating, so there is no need to apply for provisional approval to study the feasibility of operating it.

30. Grid-connected micro-hydropower uses either an induction generator or a synchronous generator. For more information on the distinction between the two generator types and the impact on interconnection with the grid, see Greacen, Engel, and Quetchenbach (2013).


33. A January 2017 report of the Electricity Supply Monitoring Initiative of the Prayas Energy Group notes that “only 16 percent of the monitoring locations in rural areas had the full six hours of power supply during peak evening hours” (http://www.watchyourpower.org).

34. In 2014 the national grid sold 2,958 GWh to retail customers and distribution franchisees sold 1,128 GWh (EAC 2015).

35. The ESMAP Global Facility for Mini Grids has initiated a project to systematically collect cost data on different types of mini grids. It plans to expand the database to include data on the costs of interconnections for different voltages, distances, and post-interconnection business models.

36. Load flow studies focus on the flow of electric power in the network with and without the distributed generator, to determine whether the normal operating range of the distributed generator will cause problems with excess or inadequate voltage at various locations in the grid over the grid’s expected variations in consumer load.

37. Short circuit studies investigate how the electricity network will respond to short circuits at various locations with the addition of the distributed generator. They seek to identify whether the current supplied by the distributed generator at the moment a short circuit occurs will create new safety hazards and if so what measures are needed to mitigate the new hazards.

38. Protection coordination studies investigate how various protection elements in the grid network (relays, breakers, fuses) function together with the addition of the distributed generator and suggest adjustments to the threshold and timing settings of these devices.

39. Peru and the northern territories of Australia have similar arrangements. However, their subsidy systems are for isolated mini grids rather than SPDs. In 2015 Tanzania’s he national electricity regulator decided that subsidies to SPDs should be provided through discounted bulk supply tariffs that apply to purchases from TANESCO, the national government-owned utility. TANESCO would be allowed to recover the discounts in its next general tariff cases. In its 2017 third-generation SPP and mini grid rules, the regulator withdrew this option.

40. PowerGen (2017) has proposed such an arrangement in Kenya.
41. The estimated UPPCL price would be somewhat higher if the cost of meter rental is added to the kWh charge. These numbers are estimated in the Castalia Strategic Advisors, Draft India Case Study, forthcoming in 2018. Castalia’s India case study is one of six case studies on mini grid policies and regulations in African and Asian countries being prepared for the ESMAP Global Facility on Mini grids.

42. Sachiko Graber and Tara Narayanan, Solar microgrids in rural India: Consumers’ willingness to pay for attributes of electricity, University of Michigan, School of Natural Resources and Environment, Master’s Practicum, 2017.

43. This recommendation is similar to a recent recommendation of the African Mini Grid Developers Association (http://africamda.org).

44. This issue is important for India, where most of the 300 million unelectrified households live in villages that are already connected to the main grid (see Palit 2016).

45. This business model, which exists in Indonesia, is explicitly allowed for in the 2016 Uttar Pradesh (India) Mini Grid Renewable Energy Generation and Supply Regulations, which allow mini grids to sell excess/surplus electricity to the distribution licensee at the interconnection point at the applicable feed-in tariff.

46. In India the technical interconnection rules of the Central Electricity Authority and the draft national mini grid policy do not allow for intentional islanding by connected mini grids (CEA 2013).

47. The Mwenga hydropower project (http://www.riftvalleyenergy.com/projects/mwenga-hydro/) and TPC (http://www.alteogroup.com/company/tpc-limited) are two examples of grid-connected mini grids with islanding capability in Tanzania. Intentional islanding is a feature of most micro grids built in countries in the Organisation for Economic Co-operation and Development (OECD). This feature is fairly common in off-the-shelf grid-ready stand-alone inverters.