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Recommendations for Remote Monitoring and Remote Control Requirements for Rooftop Solar PV Systems in Viet Nam

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Abbreviations

A0	National Load Dispatch Center (NLDC in short)
A2	Southern Regional Load Dispatch Center
AB	Air Breaker Switch
AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
API	Application Programming Interface
AT	AT command set, also known as the Hayes command set
Binh Thuan PC	Binh Thuan Power Company
BSI	Federal Office for Security and Information Technology
CB	Circuit Breaker
CHP	Combined Heat and Power
CIM	Common Information Model
DA	Data Acquisition
Dak Lak PC	Dak Lak Power Company
DCU	Data Concentrator Unit
DER	Distributed Energy Resource
DERMS	Distributed Energy Resources Management System
DG	Distributed Generation
DoS	Denial of Service
DMS	Distribution Management System
DNP	Distributed Network Protocol
DPV	Distributed PV
DR	Demand Response
DRED	Demand Response Enabling Device

DRM	Demand Response Management
DRMS	Demand Response Management System
DSO	Distribution System Operator
EEG	The German Renewable Energy Sources Act
EG	Embedded Generation
EMS	Energy Management System
ERAV	Electricity Regulatory Authority of Viet Nam
EVN	Electricity of Viet Nam
EVNCPC	Central Power Corporation (Utility)
EVNHCMC	Ho Chi Minh Power Corporation (Utility)
EVNHN	Ha Noi Power Corporation (Utility)
EVNNPC	Northern Power Corporation (Utility)
EVNSPC	Southern Power Corporation (Utility)
F81	Frequency Relay
F90	Regulating Device
FAN	Field Area Network
FCO	Fuse Cut Out
FEP	Front End Processor
FIT	Feed-In-Tariff
FTP	File Transfer Protocol
GFEMS	Generating Facility Energy Management System
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ GmbH
GPRS	General Packet Radio Service
GRMR	German Remote Meter Reading
GSM	Global System for Mobile Communications
HAN	Home Area Network
HIS	Historical Information System
HMI	Human-Machine Interface

IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IP	Internet Protocol
IT	Information Technology
LBFCO	Load Break Fuse Cut Out
LBS	Load Breaker Switch
LDC/Ax	Load Dispatch Center
LPWAN	Low Power Wide Area Network
LV	Low Voltage
M&C	Monitor & Control
MCB	Miniature Circuit Breaker
MCCB	Molded Case Circuit Breaker
MITM	Mad in the middle
MOIT	Ministry of Industry and Trade
MV	Medium Voltage
NERC	North American Electric Reliability Council
NLDC	National Load Dispatch Center (informally called A0)
NMU	Network Monitoring Unit
NPU	Network Protection Unit
NTP	Network Time Protocol
OMS	Outage Management System
OT	Operational Technology
PC	Power Corporation
PKI	Public Key Infrastructure
PLC	Power Line Communication
PLDC	Provincial Load Dispatch Center
PPA	Power Purchase Agreement

PPC	Power Plant Controller
PV	Photovoltaic
Quang Nam PC	Quang Nam Power Company
RE	Renewable Energy
REC	Recloser
RF	Radio Frequency
RLDC	Regional Load Dispatch Center
RMU	Ring Main Unit
RRC	Radio Ripple Control
RTDB	Real-time Database
RTS	Rooftop Solar
SA	South Australia
SAPN	South Australia Power Networks
SCADA	Supervisory Control and Data Acquisition
SML	Smart Message language vvvv
SWIS	South West Interconnected System
TCP	Transmission Control Protocol
TLS	Transport Layer Security
TSO	Transmission System Operator
UFLS	Under-Frequency Load Shedding
VAT	Value-Added Tax
VPN	Virtual Private Network
VPP	Virtual Power Plant
WAN	Wide Area Network

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Executive Summary

Executive Summary

1. Motivation for the analysis

The Government of Viet Nam updated the plan for electricity and renewable energy development and, in 2017 introduced the first Feed-in-Tariff scheme. Motivated by attractive schemes, 9,730 MWp of rooftop solar (RTS) systems were installed by the end of 2020, rising to represent 11% of the total generation installed capacity (see Figure A. 1). Together with ground-mounted solar PV farms, in only two years the total solar PV installed capacity had already exceeded the target set for 2030.

In the context of such fast and significant capacity growth of rooftop PV systems in Viet Nam, the need arises for a review of the local technical requirements and regulatory context surrounding RTS systems, to identify current challenges faced and propose solutions to increase visibility and control in the distribution level. The focus of this study is therefore on the review of local practices and recommendations towards remote monitoring and remote control of RTS in Viet Nam, using international best practices as reference from countries that have reached a high RTS share (Germany, Australia, and the United States – with focus on Hawaii and California)

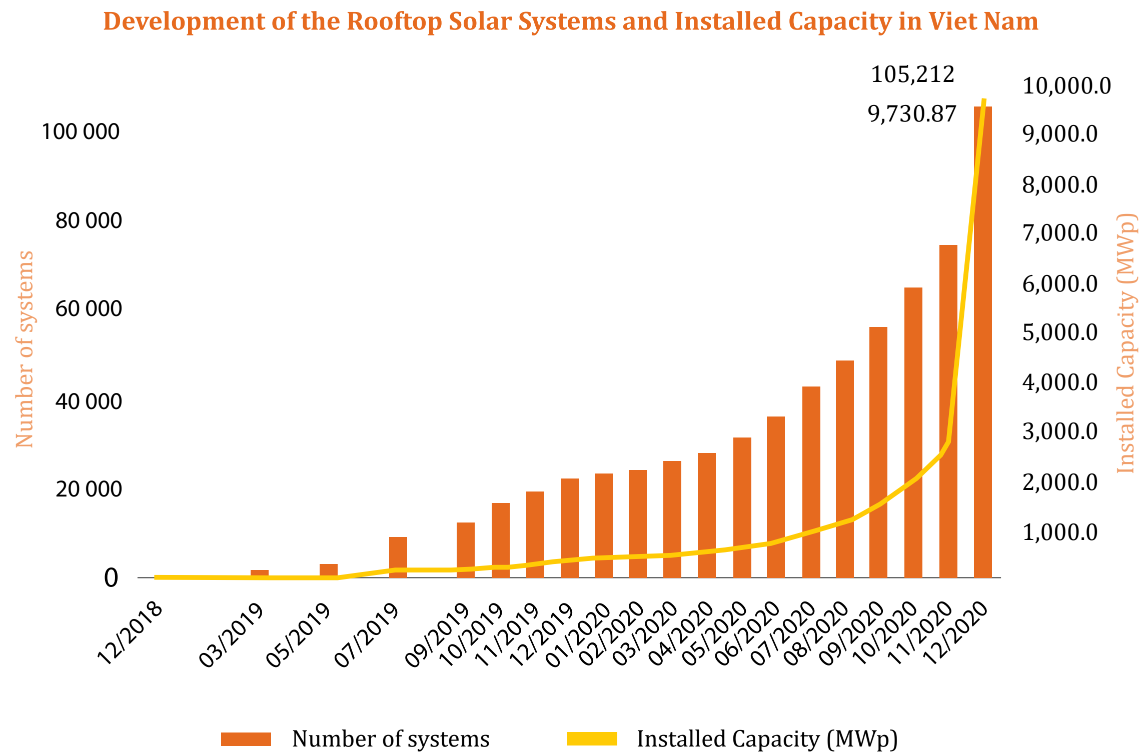


Figure A. 1. Rapid RTS systems development in Viet Nam between 2018 and 2020.

2. Summary of findings

A review of national and international practices for remote monitoring and remote control of RTS, including implementation technologies and operationalization was conducted. Key findings are shown in Table A. 1.

Table A. 1. Gap analysis main findings for remote monitoring and remote control practices of RTS.

Topic	International practices	Practices in Viet Nam
Remote control and remote monitoring capability requirement for RTS	The capability of being remotely disconnected is a minimum remote control requirement for all RTS in reviewed countries with a high RTS share. The additional capability to reduce PV system active power feed-in to certain levels (e.g. 100%, 60%, 30% and 0% of rated power) is a common requirement, based on system size or left as a DSO choice. Furthermore, remote monitoring capability is a common requirement for PV systems above 200 kWp.	Viet Nam has reached a significant rooftop solar PV share (11%), which is comparable to the shares reached in international countries reviewed (10.5% to 20.5%). However, Viet Nam does not yet have remote monitoring and remote control capability requirements for rooftop PV systems. This results in the challenge for the system operator of having little or no visibility nor controllability of RTS systems' feed-in in the current context of high RTS penetration.
Use of required RTS capability by the utility	Larger RTS systems are required to be capable of being connected to the SCADA system of the utility, however it is a decision of the utility to establish or not such communication with individual systems. Although there are several ongoing distributed energy resource management system (DERMS) pilot projects, best international practices for DERMS have not yet been defined.	Currently there is no mandatory regulation to connect RTS systems to the utility in Viet Nam. However, there are a few cases of RTS systems that have been connected to SCADA by power companies. Research is ongoing in Viet Nam and a few companies have been developing solutions for monitoring and remote control of RTS systems.
Curtailment regulations	International good practices indicate that curtailment of RTS systems should be limited to emergency situations only and the need for the curtailment must be justified to the PV system owners upon request.	Curtailment in Viet Nam is limited to emergency situations, as stated in PPA contracts. However, there was no regulation found regarding curtailment, that clearly defines the conditions in which it is allowed.

3. Recommendations

Recommendations for suitable approaches for remote monitoring and remote control of RTS in the Vietnamese context, including a technical proposal for a nationwide remote monitoring and remote control solution were outlined. The main recommendations include:

A. Remote monitoring and remote control capability

It is recommended to require rooftop PV systems above a certain size to be capable of being remotely monitored and remotely controlled, and gradually reduce the size threshold for the requirement over time, with increasing shares of solar PV in the system.

As the majority of RTS total installed capacity in Viet Nam consists of systems of 500 kWp and above, it is recommended to at least start with requiring systems of 500 kWp and above to be capable of remote monitoring and control.

Note: Performing remote monitoring and remote control of all rooftop PV systems regardless of size by the system operator is unnecessary and expensive. Therefore, the recommendation is to require only RTS systems above a certain size to be capable of being remotely monitored and/or remotely controlled (at minimum being capable of being remotely disconnected) and let Distribution System Operator (DSO) decide whether to establish the communication link to each RTS system or not in order to make use of such capabilities based on need (e.g. link to a DERMS).

B. Implementation Speed

Certain grid areas in Viet Nam have already reached high RTS penetration. For such areas, a faster and targeted solution to increase visibility and control at the distribution level might be necessary whilst expert groups design and develop an advanced solution.

Such fast and targeted solution would apply only in targeted areas where there is a critical need for remote monitoring and control at present and apply only for selected larger RTS systems (for example apply to new[1] installed RTS systems above 500 kWp), as shown in Figure A. 2. The PV system can be configured to receive control signals by the mean preferred by the DSO, with recommended means including ripple control and GSM/GPRS. Furthermore, the fast/targeted solution should be designed so that participating systems can later be included in the advanced solution without significant changes and costs.

When smart meters are in place in Viet Nam, they can also participate in the remote control solution. Their digital outputs could be used to switch relays and reduce feed-in to e.g. 4 levels.

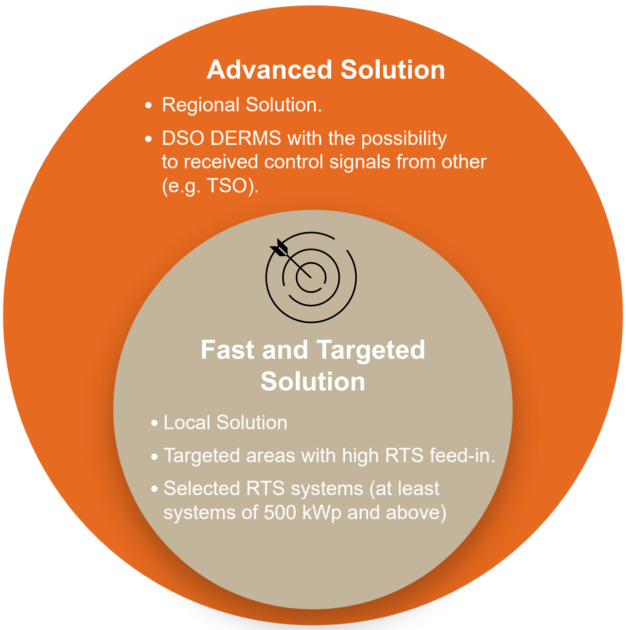


Figure A. 2. Proposed implementation steps for a remote M&C solution.

1 It is recommended to apply requirements to new RTS systems that are installed after the requirements come into force. It is not international good practice to apply requirements to already installed systems.

C. DERMS as an advanced solution

A Distributed Energy Resource Management System (DERMS) is proposed as one solution to implement remote monitoring and remote control for RTS in Viet Nam and Distributed Energy Resources (DER) in general. Minimum characteristics proposed for a DERMS system were outlined including system hardware and central software structure, specifications of smart controllers to be connected to DERs, and minimum operational performance.

In the proposed DERMS solution, DER are equipped with a Smart Controller device that will collect, centralize data and control on-site and share data with the DERMS. The smart controller supports executing control commands from the DERMS, including active and reactive power control and ramp rate control. Furthermore, the smart controller should allow the possibility to connect devices of various manufacturers.

It is important to clearly define the objectives to be achieved with the DERMS. The solution can be designed to meet the system needs and, in addition to remote monitoring and remote control, can include several other functions such as forecasting the generation of rooftop PV systems, grid analytics, data visualization and reporting. The solution should consider scalability, modularity, open standards and cyber security aspects.

D. Supplementing Circulars and regulations

The modifications to the regulatory framework required to allow monitoring and control of RTS systems must be identified and applied to have a basis for its implementation. Recommendations provided in this regard include:

- Recommendations to supplement Circular 39 and Circular 40.
- Include technical requirement for remote monitoring and remote control capability for RTS systems.
- Ensure data security of RTS investors and operation security of the power industry.
- Ensure that the responsibilities of the different stakeholders are clear (e.g. DSO, regional centres, developers, consumers).
- Ensure sufficient capacity building for dispatchers, operation management staff of local Power Company and staff operating RTS systems.
- Develop regulations on curtailment of renewable energy sources including in which (emergency) conditions curtailment is allowed, whether curtailment limits apply, measures to verify whether the system has carried out the requested curtailment, cost recovery for system owners (if any).

Furthermore, recommendations also included to limit or stop the installation of relay F81 (under-frequency load shedding relay) on certain medium voltage feeders with significant RTS shares.

4. Proposed Action Plan

An action plan, outlining the steps to implement and operationalize remote monitoring and remote control of RTS in Viet Nam is proposed. It is recommended to start with a pilot DERMS project based on international experience and with minimum capabilities enabled. In following stages, the solution can be gradually adjusted to better fit the needs of the system in Viet Nam, based on acquired learnings and stakeholder feedback, until an advanced solution is obtained. Three phases were recommended in the action plan and are summarised in Figure A.3.

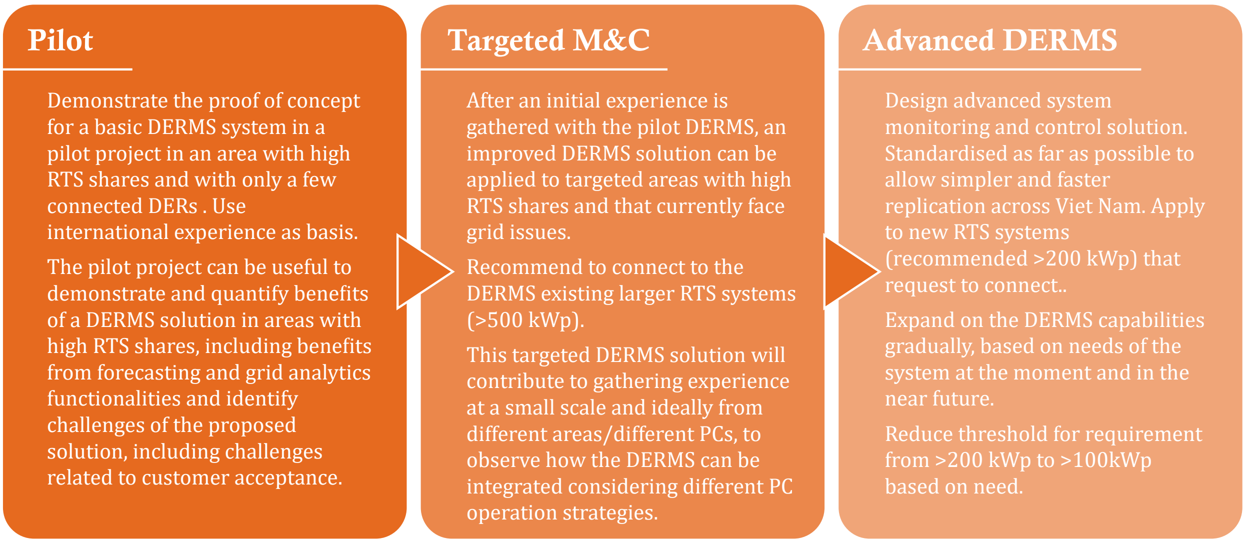


Figure A. 3. Summary of proposed steps to remote monitoring and control implementation and operationalization in Viet Nam.

The increased visibility obtained via the initial DERMS pilot project shall provide a better understanding of the current issues in an area with high RTS shares. From the identification and quantification of these issues, it will become clearer whether highly location specific services offered within a DERMS solution are necessary for such variable renewable energy (VRE) hotspot areas, or whether services from Virtual Power Plants (VPP) are sufficient. The establishment of VPPs in Viet Nam will also depend on the advances in Viet Nam's plans to develop a competition-based generation, wholesale and retail market.

Introduction

Introduction

In Viet Nam's current context of high shares of solar PV, more than half of the installed solar PV capacity is from rooftop solar (RTS) systems. RTS installed capacity grew in the last 2 years, from nearly none to 9,730 MWp reached in December 2020. Around 56% of that share is concentrated in the South of Viet Nam and 77% of nationwide installed RTS capacity is located at industrial customer premises (with an average of 482 kWp per system).

Remote monitoring and remote control of rooftop PV become necessary to contribute to maintaining grid stability and reliability. Remote monitoring of rooftop PV provides the DSO increased visibility to operate their system with increasing rooftop PV units and, combined with remote control, ensures rooftop PV can be integrated without compromising system stability and power quality increasing DSOs capability to balance the load.

With remote monitoring of rooftop solar PV and area forecast, solar PV curtailment can be reduced along with system operational costs, as dispatch will consider more accurately the generation from rooftop PV and hence improve management of power purchase from large generators. Furthermore, remote control of rooftop PV allows the Distribution System Operator (DSO) to react faster to grid emergencies and real-time monitoring of PV systems also allows for example participation in virtual power plants and market participation in rooftop PV.

In Chapter 1, the status of rooftop solar systems and remote control and monitoring systems (M&C) in Viet Nam is outlined, including relevant regulatory framework and main challenges faced with increasing RTS shares. International practices for remote control and remote monitoring of rooftop solar systems for selected countries that have reached high RTS shares (including Germany, Australia, USA) are also outlined and, a high-level gap analysis based on key findings of the international and national review is shown.

In Chapter 2, key findings from the interviews conducted with selected stakeholders are summarised, as a complement to the information gathered in Chapter 1. Based on the findings a Distributed Energy Resources Management System (DERMS) is introduced as a proposed remote monitoring and remote control implementation solution.

Finally, in Chapter 3, recommendations are provided towards remote monitoring and remote control capability requirements for Viet Nam, towards DERMS as a recommended solution considering Viet Nam's current regulations, and towards considerations to be included in the regulations. A roadmap for remote monitoring and control implementation and operationalization strategy is outlined. Furthermore, additional recommendations are made towards cyber security aspects, consideration of Virtual Power Plants versus DERMS, technical requirements for rooftop PV systems (including comments to 2022 draft circular amending Circular 39/2015/TT-BCT) as well as recommendations towards the use of relay F81.

Chapter 01

Review of local regulations and international best practices regarding remote monitoring and control of RTS

Chapter 1: Review of local regulations and international best practices regarding remote monitoring and control of RTS

1. Introduction

Renewable energy (RE) in Viet Nam has high potential, but the exploitation in previous years is limited because RE depends so much on the weather, it means uncertain, difficult to control and the investment cost is quite high. Based on the advancement of science and technology, the increasing modern electronic equipment production has made the cost of renewable energy cheaper and efficient of.

The Government of Viet Nam publised very active policies to encourage the development of renewable energy, and has attracted many sources of investments on renewable field in recent years. According to Viet Nam's renewable energy development strategy to 2030, and a vision to 2050 promulgated by the Prime Minister in Decision 2068/QD-TTg, this document encourages the mobilization of all resources to promote development and use of renewable energy and reduce dependence on fossil energy sources. Thereby, contributing to ensuring energy security, mitigating climate change, protecting the environment and developing sustainable socio-economic. The share of renewable energy in total primary energy consumption reaches about 31% by 2020; about 32.3% by 2030 and increase to 44% by 2050.

Resolution 55-NQ/TW of the 12th Politburo also emphasized that Viet Nam must develop synchronously, rationally and diversify types of energy, prioritizing exploitation, exhaustive and efficient use of energy sources, renewable, new energy, clean energy.

Viet Nam developed renewable energy sources in the form of small hydropower plants. In recent years, renewable energy produced from solar and wind energy have developed strongly. In the years of 2019 and 2020, solar farm and rooftop solar systems (RTS) were installed in a large number and capacity, which are mainly located in the central and southern provinces of Viet Nam. The total installed capacity of solar power nationwide in the end of 2020 was 19,400 MWp, equivalent to about 16,500 MW - it means about 25% of the total installed capacity of the national power system, 194% higher than the target that stated in the revised power development plan VII (850 MW). In which, the total of 105,212 rooftop solar systems (RTS) with a capacity of 9,730.87 MWp have been installed until the end of 2020.

Two reason forces in development of RTS are the Government's encouragement by tax policies, feed-in-tariff (FIT) and the trend of distributed energy resources (DERs). The Government's encouragement policies are, 20-year contracts with FIT price, and loans supplied by banks. Regarding tax, enterprises don't pay tax in the first 4 years, and pay 50% tax for the following 5 years. Regarding the Power Purchase Agreement (PPA), EVN commits to the FIT2 price of 8.35 USD cents/kWh for 20 years, so the investor estimates Return-Of-Investment time (ROI) is 6-7 years. In addition, the investors are confident to invest with availability of loans from the banks and in this case the ROI is about 9-10 years. This encouragement and sufficient support by Viet Nam Goverment, attracted many investors to participate, resulting a sudden increase of RTS in 2020.

Besides the Government's encouragement, power sources installed near the load are very important, so building the power sources right at the load is becoming a trend. Distributed energy sources (DERs) including small generators, RTS sources are increasing rapidly in huge quantity and the capacity helps reduce the power load & investment on the transmission line system. On the other hand, the power supply for self-consumption loads on site has contributed to improving the reliability of power supply and reducing the losses of the transmission line.

The capacity of RTS projects, each RTS project must be less than 01 MW (1.25 MWp) to facilitate the preparation of legal documents according to MOIT regulations. About 30% of project's capacity is more than 01 MW located in 01 location, but the investors divide it into many RTS systems so that capacity of each RTS system is less than 01 MW. In addition, many RTS systems that do not sell electricity to EVN (self-consumption model) are actively developing the projects even after FIT2 expiration, but less aggressively as compared to 2020. The number of RTS power entering the EVN grid are in huge capacity and will continue to increase in the future. Until now, a total of 92,856 RTS systems have been connected to the low voltage grid and 11,472 RTS connected to the medium voltage grid.

Many phenomena have been occurring on EVN grid when the RTS systems connect to the EVN grid, which are recorded in the Southern power grids and Central power grids. These are the overload on the electric lines, grid overvoltage, high current harmonics at some nodes, and power factor reducing. It means that the power grid needs to regulate as curtailment of the power, add reactive power..., most importantly at the position with high variable power. These above phenomena not only affect the operating and dispatching of the EVN power system, but also the power quality and reliability of the power system.

The increase of RTS lead to many challenges for power system operation. In addition, the high variable and uncertainty of the source creates investment disadvantages on RTS with more risk: Power plants have to face a variable generation schedule, and at the same time must accept curtailment when excess resources are present.

The RTS system directly effects operating and dispatching of EVN, which is a challenge. In which, the first issues are monitoring and data collection. Therefore, potential remote M&C solutions and their advantages and disadvantages will be investigated in this project.

This chapter includes 4 sections. The Viet Nam RTS status, associated with relevant regulations and current practices (curtailment, RTS technical requirements, among others) as well as current challenges with the increasing RTS were reviewed and are shown in Section 2.1. Section 2.2 shows the results of the review of international experience in remote monitoring and remote control, like in Germany, Australia, the US (focus on California and Hawaii), Italy, and Thailand. A general overview of the possible solutions and technologies associated with remote monitoring and control is provided, including possible communication architectures, application layer protocols, network structure, and communication technology. Based on the findings of the national and international review, a high-level gap analysis is provided, comparing practices in Viet Nam and international experiences. From the gap analysis, preliminary recommendations are derived and topics to be further investigated are identified, with a goal to propose one or more suitable solutions for Viet Nam regarding remote M&C.

2. Review of national regulations and practices relevant for remote monitoring and control of RTS

2.1. Main relevant regulatory framework and key requirements for RTS

With its geographical location, long coastline, and tropical climate, Viet Nam holds abundant and diverse renewable energy resources that can be utilized for energy production. According to the Viet Nam Clean Energy Association, Viet Nam is among the countries with the most sunshine in the world's solar radiation map. On average, the total solar radiation in our country ranges from 4.3 to 5.7 kWh/m2. In the provinces of Central Highlands and South-Central Viet Nam, the number of hours of sun is quite high, ranging from 2,000-2,600 hours per year. The average solar radiation of 150 kcal/m2 accounts for about 2,000-5,000 hours per year, with an estimating theoretical potential of about 43.9 billion TOE. The revised Power Development Plan (PDP)VII published in 2016 offers the outlook and plans to harness about 850 MW of solar power by 2020. This can be raised up to 4,000 MW by 2025 and about 12,000 MW can be harnessed by 2030.

The potential is there; however, only in 2014 did Viet Nam have the first grid-connected solar power project, which is the Hoi An Photovoltaic Plant in Con Dao (built from March 2014, with a capacity of 36 kWp, electricity of more than 50 MWh/year, and a total investment of about 140 thousand Euros; its connection to the power grid of Con Dao Electricity was completed in early December 2014).

To encourage solar energy development, the Government has issued many mechanisms to attract investors to develop solar power projects. According to the statistics by Electricity of Viet Nam, the total installed capacity of solar power by the end of 2020 across the country has reached about 19,400 MWp, equivalent to about 16,500 MW - accounting for about 25% of the total installed power capacity of the national electrical power system, it exceeded 194% in comparision with the target stated in the revised PDP VII (850 MW).

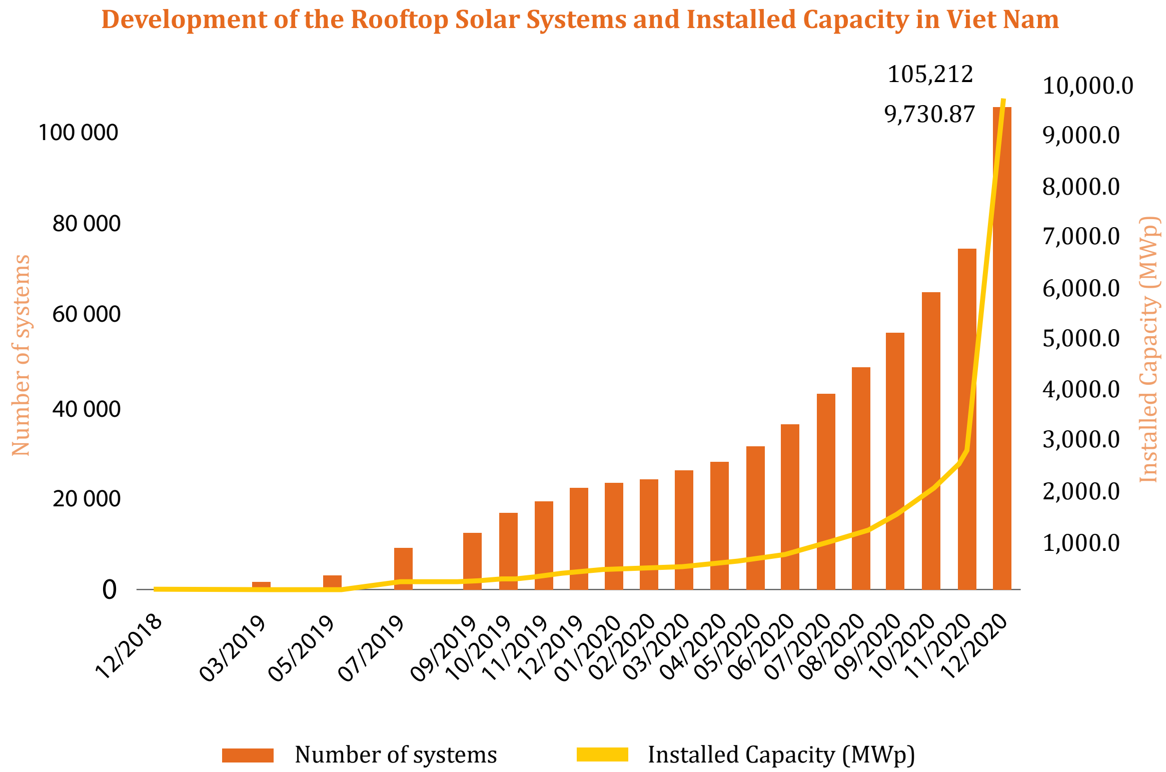


Figure 1 . Total RTS systems and installed capacity (MWp) in Viet Nam by the end of December 2020

In August 2017, the total installed capacity of solar power was only about 28 MW, which was mainly small-scale on-site power supply (off-grid areas for households and some demonstration projects connected to low-voltage grids, mainly installed on the roofs of office buildings). However, after the Government issued a mechanism to support solar power projects, the number of solar power projects have increased significantly.

By the end of December 2020, a total of 105,212 rooftop solar systems (RTS) with a capacity of 9,730.87 MWp were installed in Viet Nam (end of November 2020: 74,281 systems/2,875.5 MWp). During December 2020, 30,931 rooftop solar systems with a capacity of 6,855.4 MWp were newly installed (see Figure 1).

Power supplied to the grid in December: In December 2020, all installed rooftop solar systems delivered 216,399 MWh (in November 2020: 161,756 MWh) to the national power grid. The Southern Power Companies (EVN SPC) generated more than half of the total solar energy supplied to the grid with 121,316 MWh (shown Figure 2).

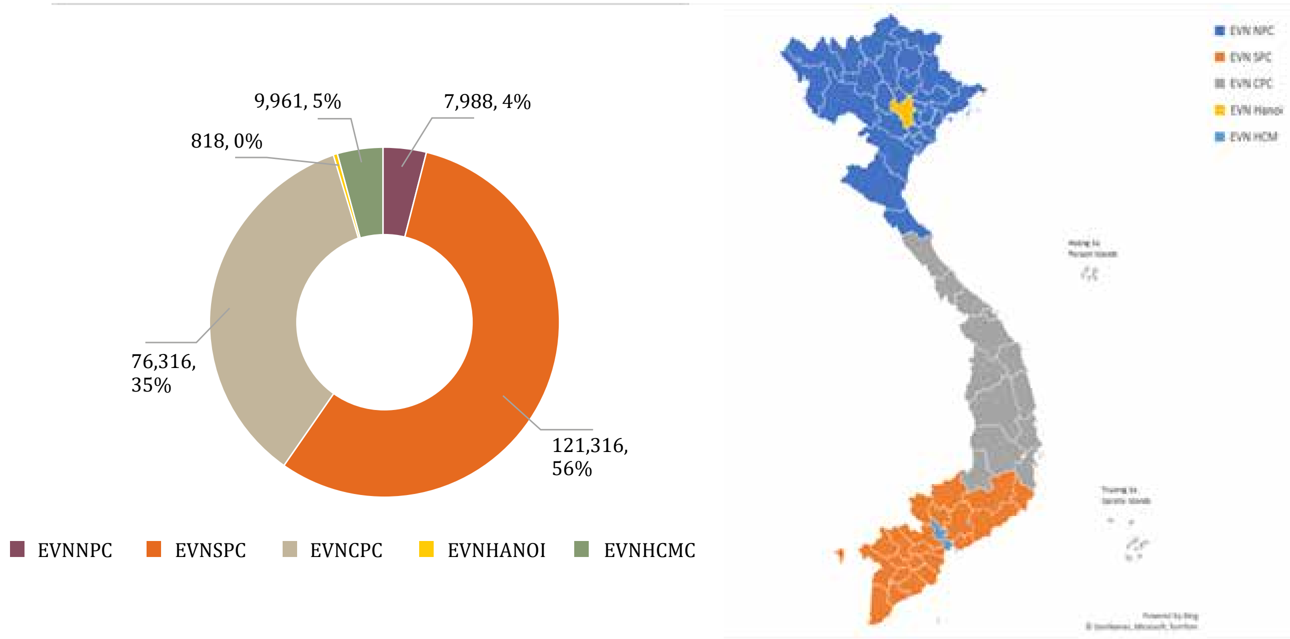


Figure 2. Total generated solar power supplied to the grid (MWh) by PC - December 2020

2.1.1. Geographical breakdown

Number of installed systems: In total, EVN SPC still have the highest number of RTS systems. EVN CPC has the second highest number of RTS systems. In December 2020, 18,383 new systems were newly installed under EVN SPC.

Installed Capacity: In December 2020, 4,200.2 MWp were newly installed under EVN SPC and 2,068.4 MWp was newly installed under EVN CPC. In total, EVN SPC and EVN CPC still have the highest installed capacity for rooftop solar in the country with 5,657.81 MWp and 3,094.85 MWp respectively (Figure 3)

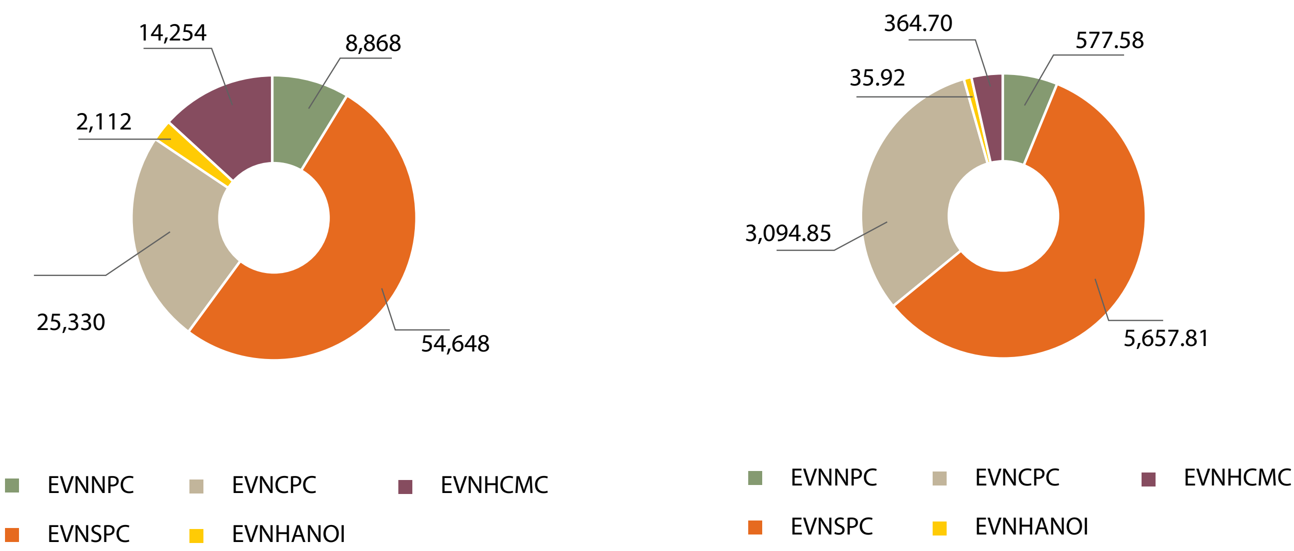


Figure 3. Breakdown of number of RTS systems and installed capacity by PC – December 2020

2.1.2. Energy consumption breakdown

Number of installed systems: Within December 2020, 19,588 household systems, 9,133 industrial systems, 1,759 commercial systems and 451 systems on public buildings were newly installed.

Installed capacity: Within December 2020, newly installed industrial RTS accounted for 5,791.65 MWp followed by household RTS with 562.16 MWp and RTS for commercial and administrative building with 392.62 MWp and 108.94 MWp, respectively Figure 4.

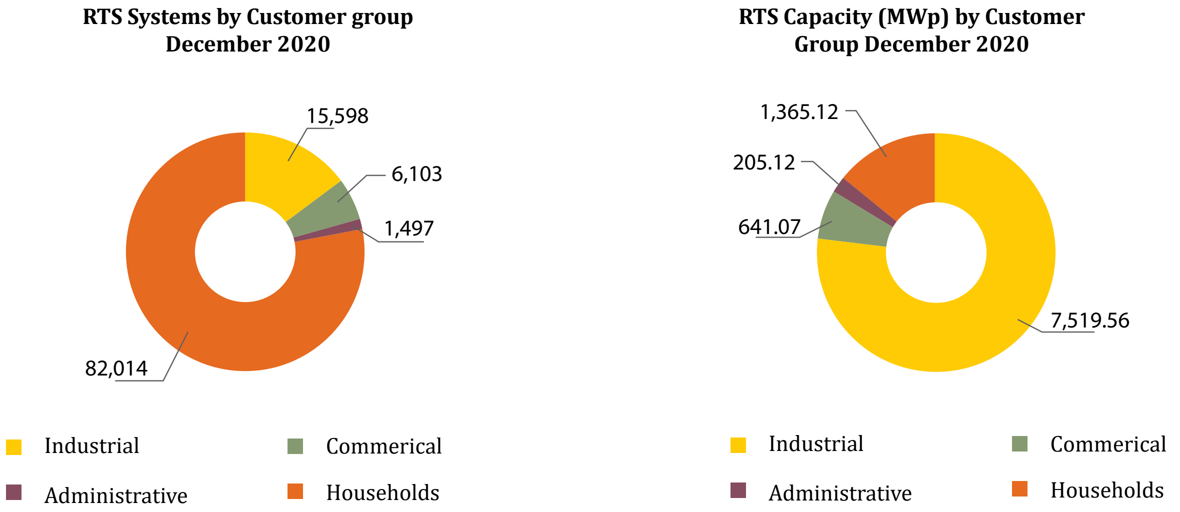


Figure 4. Breakdown of RTS systems and installed capacity by customer group – December 2020

2.2. RTS regulatory and legal framework

Rooftop solar power is the current trend of sustainable energy development. This is also a type of renewable energy that takes advantage of the roof space in residential areas and businesses, which already have adequate grid infrastructure, convenient for grid connection... The Government of Viet Nam has issued many mechanisms to encourage economic sectors such as households, industry and commercial zone to invest in supplying electricity for their own use and the remainder to be sold to Electricity of Viet Nam (EVN).

A list of key legal documents, governments policies, guidelines, regulations that governs RTS deployment as listed below:

No.	Name of document	Description	Main requirements related to RTS
A. Issued by the Government and Prime Minister			
A.1 Strategy and orientation			
1	Decision No. 2068/ QD-TTg on 25 November 2015 of the Prime Minister	Approving development strategy of RE of Viet Nam until 2030 with a vision to 2050	Gradually increase the RE share in the national energy production and consumption in order to ensure less dependence on fossil sources, and contribute to better energy security, mitigating climate change, environmental protection and sustainable socio-economic development
2	Decision No. 428/ QD-TTg on 18 March 2016 of the Prime Minister	Approval of the Revised National Power Development Master Plan for the period of 2011-2020 with a vision to 2030	Accelerated development of solar power, including large ground-mounted and small rooftop systems: Bringing the total solar power capacity from the current negligible level up to approx. 850 MW in 2020, approx. 4,000 MW in 2025 and approx. 12,000 MW in 2030.
3	Resolution 55-NQ/ TW on 11 February 2020 of Central committee of the communist party of Vietnam	On the orientation of the Viet Nam's National Energy Development Strategy to 2030 and outlook to 2045	Prioritize full and efficient exploitation and use of renewable energies, new and clean energies; The share of renewable energy sources in the total primary energy supply reaches 15 - 20% in 2030 and 25 - 30% in 2045
A.2 Supporting mechanism			
4	Decision 11/2017/ QD-TTg on 11 April 2017 of the Prime Minister	Support mechanisms for the Development of Solar Power Projects in Viet Nam	FIT for both RTS and solar farm (9.35 US cents/kWh)

5	Decision No. 02/2019/QD-TTg on 08 January 2019 of the Prime Minister (the mechamisn was valid to 31 December 2020)	Amendments and supplements to certain articles of Prime Minister's Decision No. 11/2017/QD-TTg dated April 11, 2017 on Mechanism for Encouragement of Development of Solar Power in Viet Nam	FIT for both RTS and solar farm (9.35 US cents/kWh)
6	Decision 13/2020/ QĐ-TTg dated 06 April 2020 of the Prime Minister	Encouraging mechanism for the development of solar energy in Viet Nam	RTS: PV installed on the roof of constructions, < 01 MV, direct/ indirect connection to medium-voltage (MV) network (<35 kV). Implementation: RTS (Chapter III) must register for connection with EVN or EVN's authorized entity. EVN to invest, install and maintain meters. Organizations and individuals investing in the installation of RTS must meet the requirements on electrical safety, construction safety, fire prevention and environmental protection in accordance with current regulations.
B.	***Issued by MOIT***		
1	Circular 40/2014/ TT-BCT dated 05/11/2014 of Ministry of Industry and Trade	Stipulating the procedure for dispatching of national power system	General provisions on power system dispatching
2	Circular 39/2015/ TT-BCT dated 18/11/2015 of Ministry of Industry and Trade	Regulating electricity distribution system	Regulating order and procedure for negotiation/agreement on connection to distribution grid (Part 3)
3	Circular 16/2017/ TT-BCT of Ministry of Industry and Trade dated 12/09/2017	Project Development and Standardized Power Purchasing Agreement for Solar Power Projects	

4	Circular 30/2019/TT-BCT dated 18/11/2019 of Ministry of Industry and Trade	Amending, supplementing a number of articles in Circular 25/2016/TT-BCT and Circular 39/2015/TT-BCT	Regulating amendment, supplementation of regulations for electricity distribution system
5	Decision no. 55/QĐ-ĐTĐL dated 22/8/2017 of Electricity Regulatory Authority of Viet Nam	Technical requirements and operation management of SCADA system	SCADA/EMS/DMS/OMS
6	Circular 18/2020/TT-BCT dated 17/7/2020 of Ministry of Industry and Trade	Regulating the project development and standard sample power purchase agreements applicable to solar power projects	1. Register for connection (location, Size <1,25 MWp, line, expected connection point) 2. Submit dossier offering selling of electricity (PV's technical documents, Inverter, lines, MV Substation, CO/CQ) 3. All parties shall perform technical inspection, install electricity meter, conclude meter readings, sign contracts for electricity sale, energize and bring the system into operation. 4. The Seller must guarantee that the inverter is capable of isolating electricity flow into power grids of the Buyer when the grids are neutral to prevent possibility of interference and taking over of operational supervision of external factors and complying with standards, regulations and law on electricity quality. 5. Connect to SCADA system (Contract, Annex A: Connection agreement) 6. Standard sample PPA applicable for RTS system (Annex 2)
7	Technical guidance HDKTXD: 2020 of Ministry of Construction	Technical guidance related to construction safety when installing rooftop solar power system	Technical guidance related to construction safety when installing rooftop solar power system with capacity less than 01 MW.

Document issued by MOIT, EVN and other agencies:

No.	Name of document	Description	Main requirements related to RTS
1	Document no. 4725/EVN-KTSX dated 11/11/2015 of EVN.	Orientating Remote Control Center and unmanned substations.	Regulating protocols at Remote Control Centers
2	Document no. 5711/EVN-VTCNTT dated 06/11/2018 of EVN.	Using cellular network to be data transferring channel.	Connection solution for virtual separated network using APN (Access Point Name) to directly exchange data from network provider to the users' system.
3	Document no. 1532/EVN-KD dated 27/03/2019 of EVN.	Implementation instructions for Solar Power	Guidance on pricing mechanism, contract signing and acceptance.
4	Document no. 7088/BCT-ĐL dated 22/9/2020 of Ministry of Industry and Trade.	Guiding the implementation of RTS.	Construction works shall comply with regulations prescribed at Clause 10, Article 3 of the 2014 Law on Construction (1.b.i). Rooftop of construction works shall comply with regulations at Annex 2, Circular 03/2016/TT-BXD in 2016. In case there are many RTS systems with capacity >01 MW at the same location (buy back), it is not allowed to combine into one contract. That means each connection point has one PPA. In case, a solar power system with capacity <01 MW which is not installed on the rooftop of a construction work, solar power of livestock and cultivation farms with size >01 MW, solar power connected to the grid >35 kV then the RTS's tariff is not applicable.
5	Document 3288/ C07-P4 dated 08/9/2020 of the Viet Nam fire and rescue Police Department.	Guiding the appraisal and approval of fire protection and fighting design for solar power plants and RTS systems.	Guiding and determining on the RTS systems that need and do not need to have firefighting designs approved (depending on rooftop installations of constructions of different sizes, structures and uses).

6	Document no. 6948/EVN-KD dated 19/10/2020 of EVN.	Guiding the implementation for RTS development following Decision 13/2020/QĐ-TTg.	Deploying details of Decision 13, Circular 18, Document 7088/BCT-ĐL dated 22/9/2020 and with flowchart. Low voltage grid connection: total solar power < substation's capacity < 20 kWp: single phase or three phase connection; > 20 kWp: three phase connection and single-phase connection is applicable when there is only local grid with single-phase. Low voltage grid connection: comply with Article 43-51 (Circular 39) and Clause 14-18 (Circular 30). Prioritize the installation of meter at low voltage side. Dossier offering selling of electricity (2.c) and technical inspection (2.d): grid generation is not allowed when there is no voltage, other categories will be reviewed based on the technical dossier provided by the investor.
7	Document no. 10466/EVN SPC-KT dated 01/12/2020 Southern Power Corporation.	Guiding the order for connection agreement of RTS into medium voltage grid following document No. 6948/EVN-KD.	The order for connection agreement of RTS into medium voltage grid. Requirements on dossier and documents. Calculated data on impact of the project to the grid at connection point.
8	Document no. 8420/EVN-KD dated 25/12/2020 of EVN.	Develop RTS after December 31, 2020	Stop signing contracts for RTS and wait until a new mechnism.
9	Document no. 4304/ĐĐQG-PT dated 10/11/2021 of National Load Dispatch Center.	Guiding document on technical requirements for RTS inverter that are connected to medium voltage and have installed capacity of 500 kWp or more.	Organize installation and check. The installation of the set value for the control and protection system of the MV grid-connected inverter must ensure to comply to Clause 11, Article 2 (Circular 30), ensuring the operating requirements of the device. Ensure RTS does not change the operating mode, give priority to the generation of active current.

10	Document no. 9412/EVN SPC-KT dated 20/10/2021 of Southern Power Corporation.	Guiding document on technical requirements for RTS's inverter.	Guiding installation of RTS's inverter >500 kWp.

To encourage more economic sectors to participate in the development of renewable energy sources such as biomass, solar and wind power, many countries in the world have policies issued on mechanisms to support investors to develop renewable energy projects, such as compensation mechanism, metering arrangement, feed-in-tariffs (FIT)… In Viet Nam, the Government has also issued many mechanisms and policies to promote the development of renewable energy sources, including rooftop solar power.

Key aspects of the feed-in tariffs, technical requirements for RTS, monitoring and control requirements, etc [topics covered in sections 2.2.1 -2.2.7] will be introduced in the remainder of this chapter.

2.2.1. Feed in tariff

Viet Nam has two different stages of programs on FIT for RTS, which are:

- The first program on FIT for RTS system which achieved commercial operation date ("COD") by 30 June 2019 (FIT 1).
- The second program on FIT for RTS systems which achieved commercial operations between 1 July 2019 and the new FIT deadline by 31 December 2020 (FIT 2).

After the FIT programs, it is intended that a new competitive bidding mechanism (also known as solar auction or reverse auction for solar PV projects) would potentially be applied to determine the tariffs on other solar power systems / projects which are not eligible for the FIT programs. For rooftop solar, it remains unclear for the period after the end of 2020.

RTS FIT 1

In 2017, Viet Nam became the fifth country in Southeast Asia to initiate a program to support self-consumption of electricity generated from rooftop solar systems. Decision No. 11/2007/QD-TTg, issued in April 2017, directed roles of related agencies in the promotion of ground-mounted and rooftop solar PV and established incentives to promote investment in solar PV. Pursuant to this Decision, rooftop solar systems could benefit from a net metering scheme in which the excess energy generated from the systems in each payment cycle could be accumulated as credits, which could then be used to offset consumption in following payment cycles. Remaining credits at the end of the payment cycles or at end of the year would be reimbursed by the electricity distribution company at the FIT rate of 9.35 USD cents/kWh. The Decision No. 11/2007/QD-TTg was active only from June 1, 2017 to June 30, 2019, and the Ministry of Industry and Trade via the Electricity and Renewable Energy Authority (EREA) has been tasked with proposing new support mechanisms applicable to both ground-mounted and rooftop solar projects to replace this Decision.

Salient features of Decision 11/2017/QD-TTg related to rooftop solar power are depicted in the table below:

Salient point	• **Solar power development plant built a vision for 2030 at a national and provincial scale, for grid connected projects** • **Introduced the net-metering scheme for RTS projects**
Counterparty	• EVN to buy all electricity produced by approved solar power projects
Pricing mechanism	• The electricity purchase price shall be adjusted as per variations in VND/USD exchange rate (on the final exchange rate announcement date of the preceding year). • Recommended retail price (RRP) for grid-connected projects is listed at 9.35 US cents/kwh both type of solar projects- rooftop and ground mounted. The tariff applicable considering exchange rate fluctuation is VND 2,086/kWh before Jan 1st, 2018, VND 2,096/kWh for 2018 and VND 2,134/kWh for 2019. • This tariff is applicable for the term of PPA • It is applicable to grid connected solar PV projects with solar sell efficiency of greater than 16% (or module efficiency of greater than 15%). • Implement rooftop projects via net metering with two-way electricity meters. If the volume of electricity generated is greater than the amount consumed, the surplus is carried forward to the next trading cycle. At the end of the year or upon termination of the agreement, surplus amount of energy will be sold to the buyer at the price specified in the power purchase agreement (refer to the price above).
Incentives	• There are incentives such as investment capital and tax incentives[2] potentially allocable. • Land incentive[3] - solar PV projects and transmission lines and sub-stations for connection to the national power grid are exempt from land use levies and land rents in line with the current law for projects in the field of investment incentives); import tax exemption[4] (raw materials, supplies and semi-finished products that cannot be produced domestically).
Contract term	• Sale of electricity on a standardized Power Purchase Agreement with a 20-year term, and extended as mutually agreed by the parties.

2 Decree No. 118/2015/NĐ-CP dated 12 November 2015: Article 16
3 Decree No. 46/2014/NĐ-CP dated 15 May 2014: Article 19, Article 20
4 Circular No.83/2016/TT-BTC guiding the implementation of investment incentives: Article 5

To provide for detailed guidance for implementation of Decision 11/2017/QD-TTg dated 11 April 2017 of the Prime Minister on mechanisms for encouraging development of solar power projects in Viet Nam, the MOIT issued Circular No. 16/2017/TT-BCT ("Circular 16") dated 12 September 2017 on project development and standard form of power purchase agreement ("Model PPA") for solar power projects, with effect from 26 October 2017. Below are key points introduced under Circular 16/2017/TT-BCT:

Salient point	**It specifies for a solar project:** • **Planning and development aspects,** • **Sell price of electricity generated by grid connected solar projects and rooftop solar power projects,** • **Standard PPA for grid and rooftop projects, and (iv) role of key institutions.**
Limiting conditions	Circular 16 sets out the conditions for developing a solar project. A project must be contained in the provincial or national master plan for solar power development, and if it is not, the sponsor should apply for such a listing
Licensing requirements	Solar projects, both grid-connected and rooftop, of capacity 1 MW or above must meet licensing requirement of the MOIT.
Power purchase agreement	• The use of model PPAs is mandatory for the sale and purchase of power generated from rooftop projects between the owner of a rooftop project and the power purchaser (i.e., the relevant local/ regional EVN's Power Corporations). • Parties to this model PPA (i.e., the building owner and EVN) may supplement certain contents to the model PPAs to clarify their rights and obligations but may not change the substantial contents of the model PPAs. • As such, the room for negotiation or revisions or amendments to the model PPAs are generally limited.

In addition, on January 8, 2019, the Government of Viet Nam issued Decision No. 02/2019/ QD-TTg amending and annulling some regulations of Decision No. 11/2017/QD-TTg on the mechanism for encouraging the development of solar power in Vietnam. Decision 02/2019/ QD-TTg took immediate effect upon its issuance. Below are some notable points of Decision 02/2019/QD-TTg:

Table 1. Demand Response Modes

Salient point	• **Promulgates new payment scheme to address the net-metering issue of the RTS power projects under Decision 11.** • **Responsibilities of government agencies particularly MOIT and MOF are amended.**
New payment scheme for RTS projects	• Rooftop solar power projects shall be entitled to a mechanism for purchase and sale of electricity that separates the direction of delivery of electricity from the direction of receipt of electricity in two-way/bidirectional meters. This mechanism has replaced the previous net-metering scheme under Decision 11. • Accordingly, the electricity seller must pay for any energy output received from EVN's power grids (i.e., import energy if any) in accordance with the relevant existing regulations (i.e., retail tariff with EVN). • On 20 March 2019, the MOIT issued Decision No. 648 to specify the new average retail power tariff level of VND 1,864.44 per kWh (exclusive of VAT) as well as the new retail tariff rates to be applied from 20 March 2019. Accordingly, the retail electricity tariff structures and allocations vary between different types of customers (industrial, commercial and household / residential), voltages and time-of-use (peak, normal and off-peak hours), as detailed in Annex A1. • The electricity buyer (i.e., relevant EVN's Power Corporations) shall pay for any energy output generated to EVN's power grids from rooftop solar power projects (i.e., export energy if any) at the purchase tariff as regulated by the MOIT, as discussed further below. • All rooftop solar power projects having their commercial operation date (operation and metering confirmation) prior to 1 July 2019 enjoyed FIT of 9.35 US cents/kWh under Decision 11. The price of rooftop solar power for the following year must be adjusted according to the exchange rate between Vietnamese Dong and US Dollar issued by the State Bank of Viet Nam on the last date of release of the exchange rate in the previous year. • Removes the condition that the electricity is sold to the buyer once a year, at the end of the year, or when the contract is terminated. • The MOIT shall promulgate technical regulations on solar power, regulations on measurement of energy of solar power projects and provide instructions on the connection, installation of electricity meters and the calculation of rooftop solar power project.

Change in responsibilities of government agencies	• The Ministry of Industry and Trade now promulgates regulations on connection of solar power projects and it is no longer required to provide instructions on the calculation of the net-metering mechanism, as such, mechanism has been removed. • The Ministry of Industry and Trade is also required to provide instructions on calculating purchase prices for solar projects in accordance with the VND-USD exchange rate; instead of imposing adjusted purchase prices for solar power projects for the following year based on the VND-USD exchange rate. • The Ministry of Finance is no longer required to consider amending regulations on exemption of rooftop projects from taxes and fees.

MOIT promulgated Circular 05/2019/TT-BCT dated 11/03/2019 amending Circular 16 and providing providing additional guidelines on the payment mechanism for energy output generated and exported from rooftop solar power projects to EVN's grids.

Table 2. Salient features of Circular No. 05/2019/TT-BCT

Salient point	• **Effective from 25 April 2019, Circular No. 05 provides a new model power purchase agreement (PPA) template for rooftop solar power projects, replacing the previous Circular No. 16's rooftop solar PPAs for implementing the new scheme of Decision No. 02 for rooftop solar.** • **It also includes further clarifications on tariff payments for power exported from rooftop solar power systems to EVN's grids, invoicing and payment settlements, required timelines and obligations of rooftop power generators and EVN.**
Abolishing the net-metering mechanism	Circular 05 abolished the payment calculated by the net-metering mechanism for rooftop solar power projects. Particularly, amount of power loaded from project to grid and amount of power received from grid will be separately calculated without using net-metering mechanism.
Calculating the power purchase price	Circular 05 amended Article 16 of Circular 16 as follows: • Before 1 January 2018, the power tariff was VND 2,086 per kWh (excluding VAT, equivalent to 9.35 US cents per kWh, based on the central exchange rate of VND 22,316/USD announced by the State Bank of Viet Nam on 10 April 2017); • From 1 January 2018, the power tariff above will be adjusted in accordance with the VND-USD exchange rate fluctuation based on the central exchange rate of Vietnamese Dong to US Dollar announced by the State Bank of Viet Nam on the preceding year's last date of announcement of such exchange rate.

Energy payment and billing period	• Under Circular No. 05, based on power output agreed by both parties and the power tariff as discussed above, EVN is required to make energy payments to the power seller for power exported on a monthly basis. • In terms of timeline relating to EVN's payment, Circular No. 05 provides that it must be made within seven (7) working days from the date on which: a. the power seller agrees with EVN on meter readings and output of power generated and exported to EVN's grid (as notified by EVN), and b. Sufficient set of payment request and supporting documents has been submitted to EVN. Documents like statements of monthly meter readings and energy output, invoices issued by the power generator (in case the power generator is a business company which issues invoices on a monthly basis); and relevant tax documents including applicable taxes and official fees (if the revenue is subject to taxes) • If EVN fails to make energy payment to the power seller within the above-mentioned timeline, Circular No. 05 provides that EVN is required to pay late payment interest on the entire number of late payments, which will be accumulated the date after the due date until the date on which EVN makes actual payment. The late payment interest is determined based on a one (1) -month average interbank interest rate as announced by the State Bank of Viet Nam at the time of EVN's payment.
Amendments to the model power purchase agreement	• The annual power purchase price of agreement will be amended based on the central exchange rate of Vietnamese Dong against the US Dollar announced by the State Bank of Viet Nam on the last announcement day of the previous year; • Regulating on monthly payment for amount of power loaded from project to grid to project owner being enterprise and project owner being individual or organization other than enterprise; • There is no longer regulation on the net-metering mechanism; • Regulating the payment and invoice issuance of value added tax to the revenue from power loaded from project to grid.

Note that: Under Article 12.2 of Decision 11, sellers of electricity from rooftop solar projects were required to sell electricity to buyers based on the net-metering method, with two-way electricity meters. If the amount of electricity generated from rooftop projects was greater than the amount consumed by the seller, the surplus would be carried forward to the next trading cycle. At the end of the year or upon termination of the contract, any surplus electricity would be sold to the buyer at a specified price. However, under Decision 02, the net-metering method has been replaced with the direct consumption – direct supply method. Buyers will now have to directly/separately pay for the amount of electricity they receive from rooftop project sellers, while sellers must directly/separately pay for the electricity they receive/consume from the power grid. It is worth noting that Decision 02 also removes the condition that the electricity is sold to the buyer once a year, at the end of the year, or when the contract is terminated.

RTS FIT 2

The new decision will fill the gaps of Decision No. 11/2017/QD-TTg dated April 2017 as amended by Decision No. 02/2019/QD-TTg dated January 2019. Overall, Decision 13/2020/QD-TTg on 6 April 2020 draws a clear distinction between grid-connected solar power projects and rooftop solar power ones, each enjoying different regimes and feed-in tariffs (FIT). This new Decision was in effect from 22 May 2020, specifying the new electricity purchase price applicable to grid-connected solar power projects which have been approved by the competent authorities before 23 November 2019 and the commercial operation date between 1 July 2019 and 31 December 2020 (except for the projects already planned in Ninh Thuan province with the commercial operation date before 1 January 2021 with no more than 2,000 MW accumulative capacity which are subject to the old purchase price).

Overall, the classification of such power schemes under Decision 13 remains the same as Decision 11 whereby solar ones are divided into grid-connected solar power schemes, and rooftop power ones. However, Decision 13 has provided better clarity by further classifying grid-connected power projects into two types – those of floating solar power and ground-mounted solar power. Floating power projects are a new entrant in Viet Nam's solar sector and it is defined as the grid-connected solar venture with photovoltaic panels installed on a floating structure on the water surface. Other grid-connected solar power projects which are not floating power in type will be taken as ground-mounted solar power projects. Although both floating solar power and ground power ventures are grid-connected, they would enjoy a different FIT rate under Decision 13.

Similar to Decision 11, the term of the model PPA will be 20 years from commercial operation date (COD) for grid-connected solar power projects. With regards to a rooftop project whose power purchaser is EVN or its authorized member units, the term of the model PPA shall not exceed 20 years from the power generation date.

Under Decision 13, electricity purchasers, EVN, its member units, or other parties are required to purchase all electricity produced by the project connected to the national grid system. This may be deemed a move to lower the risks of curtailment for the electricity producers, thereby encouraging investors to participate in the solar energy market.

However, Decision 13 to an extent limits the electricity purchase obligation of purchasers to only "all electricity produced for the national grid", whereas the previous Decision 11 required purchasers to purchase "all electricity produced from solar power projects".

As noted above, new to Decision No. 13 is the inclusion of floating solar systems and ground power schemes in the definition of grid-connected solar power projects. Floating power systems, although still required to comply with requirements applicable to all grid-connected power projects, enjoy a more favorable FIT.

If the purchaser is EVN or its member units, the applicable FIT will be applied as table below:

Table 3. FIT 2 Rates

Type of solar project	FIT (US cents/kWh) (excluding VAT)
Floating solar project	7.69
Ground mounted solar project	7.09
RTS project	8.38

Rooftop solar power systems under Decision 13 are defined as those with photovoltaic panels installed on the roof of a construction work and having a capacity of not exceeding 1 MW, directly or indirectly connected to the grid with a voltage of 35 kV or less of the electricity purchaser. The 1 MW capacity threshold, although absent in the previous Decision 11, falls in line with Circular No. 16/2017/TT-BCT dated September 2017 regulating project development and model PPA applied to solar power projects. Accordingly, rooftop solar power schemes with capacity exceeding this threshold will be subject to master planning related procedures, which is similar to other grid-connected power projects. In order to connect to the national grid directly or indirectly, rooftop power projects must register for connection with EVN or its authorized member units. This provision would facilitate the investors in terms of better security for connecting their rooftop solar power projects, while simultaneously ensuring that the national grid is not congested or overloaded. Also, EVN would be responsible to invest, install, and maintain the electricity meter.

Under Decision 13, the investors of rooftop solar power ventures could sell the power generated by their rooftop power systems to (i) EVN or its members by entering into a model PPA, or (ii) other individuals or organizations by entering into a private PPA. As the private PPA would be negotiated between the parties, the provisions of Decision 13 as discussed below apply to the rooftop solar power project having the purchaser as EVN or its authorized members.

In order to enjoy this FIT, solar power projects must: (i) have obtained an in-principal investment approval from competent authorities before 23 November 2019; (ii) have COD between 1 July 2019 and 31 December 2020, and (iii) have a solar cell capacity of more than 16 per cent or a solar module of more than 15 percent.

In line with Resolution No. 115/NQ-CP dated August 2018 on the application of special mechanisms and policies for the socio-economic development of Ninh Thuan province, solar projects in this province may enjoy a more favorable FIT of VND 2,086/kWh, equivalent to 9.35 US cents per kWh. This FIT will be adjusted in accordance with any fluctuations of the applicable VND/USD exchange rate. Such favorable FIT applies to projects in Ninh Thuan Province that (i) have been included in the regional power development master plan, (ii) have COD before 1 January 2021, (iii) have the total accumulated capacity not exceeding 2,000 MW; and (iv) have solar cell capacity of more than 16 per cent or solar module of more than 15 percent.

To stipulate and guide implementation of the Decision No. 13/2020/QD-TTg of Prime Minister, MOIT issued the Circular 18 dated April 6, 2020 on mechanisms to encourage developing solar power projects in Viet Nam.

Circular 18 introduces updated template power purchase agreements (PPA) as well as revised regulations for the development of grid-connected solar farms and rooftop solar power systems. Despite rapid growth and significant investment potential, the Vietnamese renewable energy market and the associated regulatory regime remain highly complex and constantly evolving.

Circular 18 provides that where a proposed grid-connected rooftop solar system has a capacity of no more than 01 MW, it is not necessary to obtain a formal power generation license. This is consistent with current regulations and reaffirms the position under Circular 36/2018/TT-BCT issued in 2018 by the Ministry of Industry and Trade on procedures for issuing and revoking electricity licenses.

Rooftop solar developments with a 01 MW capacity or less (AC capacity) or a 1.25 MWp capacity or less (DC capacity) must nevertheless register their proposed connection with Electricity of Viet Nam (EVN), including details of location for installation, output scale, and proposed connection point.

The template PPA for rooftop solar system projects is largely the same as the template provided under Circular No.05/2019/TT-BCT, albeit with the following noteworthy amendments. However, a new template PPA introduces greater flexibility with regards to late payments. Parties are now free to include a late payment interest clause in an amount as agreed between the parties, in accordance with Commercial Law 2005. The previous template PPA under Circular 5 limited the calculation of late payment interest to an amount based on the State Bank of Viet Nam's monthly interbank interest rate.

2.2.2. Technical requirement for RTS connection

According to the RTS definition mentioned in the Decision 13, RTS system means a solar PV system with photovoltaic panels mounted on the rooftop of construction works with an output not exceeding 1 MW, directly or indirectly connected to the Electricity Buyer's grid with a voltage of 35 kV or less. This means that the RTS system will be connected to the low and medium-voltage grid.

The technical requirements for the RTS system connected to the distribution grid at low and medium voltage level is described in the Circular No 39/2015/TT-BCT dated 18 November 2015 on stipulating the electrical distribution system and the Circular No 30/2019/TT-BCT dated 18 November 2019 on amending and supplementing to several articles of Circular 25/2016/ TT-BCT regulating Electricity Transmission System and Circular 39/2015/TT-BCT regulating Electricity Distribution System.

Pursuant to Article 40, the requirements for solar power plant connected to the distribution grid from the medium voltage level are as follows:

- The plant should be able to generate active power in the frequency range from 49 Hz to 51 Hz under the following modes: a) free generation mode: generate as high capacity as possible according to change of primary energy sources (wind or sun); b) generation capacity control mode: solar power plant should be able to adjust generation of reactive power according to command of the authorized dispatch level in alignment with change of the primary energy source in no more than 30 seconds with an error of ± 01 % of the nominal capacity, specifically: (i) generate capacity according to dispatch command in the case that primary energy source is equal or higher than the forecasted value; (ii) generate as high capacity as possible in the case that the primary energy source is lower than the forecasted value.

- Solar power plant at all times of grid connection should be able to maintain power generation in the minimal duration corresponding to frequency ranges.

- Solar power plant connected to the distribution grid should be able to adjust active power and voltage as follows:

  ◊ In the case that the power plant generates an active power more than or equal to 20% of nominal active power and the voltage falls under the normal operational range, the power plant should be able to continuously adjust reactive power in the power factor range of 0.95 (corresponding to the mode of generating reactive power) to 0.95 (corresponding to the mode of receiving reactive power) at the connection point corresponding to the nominal capacity.

  ◊ In the case that the power plant generates active power of less than 20% of the nominal capacity, the power plant can decrease capability of receiving or generating reactive power in alignment with characteristic of the generation unit.

  ◊ In the case that voltage at the connection point falls within the range of ± 10 % of the nominal voltage, the power plant should be able to adjust the voltage at the connection point with an error of no more than ± 0.5 % of the nominal voltage in the permissible working band of generator and complete in no more than 02 minutes.

  ◊ In the case that the voltage at the connection point falls out of the range of ± 10 % of the nominal voltage, the power plant should be able to generate or receive reactive power (corresponding to the nominal reactive power) which is at least equal to two times of the voltage change rate at the connection point.

- Solar power plant should cause no negative sequence component of the phase voltage at the connection point of more than 01% of the nominal voltage. Wind power plant, solar power plant should be able to suffer negative sequence component of the phase voltage at the connection point up to 03% of the nominal voltage for the voltage level 110 kV or up to 05% of the nominal voltage for the voltage level less than 110 kV.

- Total harmonic distortion caused by wind power plant, solar power plant at the connection point should not be more than 03%.

- Flicker caused by wind power plant, solar power plant at the connection point should not be more than the value specified at Article 8 of this Circular.

Article 41 of the Circular 39 stated that: the solar power system connected to the low-voltage grid should satisfy the following requirements:

- Connection capacity:

  ◊ Total installed capacity of the solar power system connected to the low-voltage level of the low voltage substation should not be more than 30% of installed capacity of the substation;

  ◊ The solar power system with capacity of less than 03 kVA is connected to the single-phase or three-phase low-voltage grid;

  ◊ The solar power system with capacity of 03 kVA to 100 kVA (but no more than 30% of installed capacity of the connected low-voltage substation) is connected to three-phase low-voltage grid

- The solar power system should be able to continuously maintain power generation in the frequency band of 49 Hz to 51 Hz. When frequency of the electrical system falls out of the band from 49 Hz to 51 Hz, then the solar power system should be able to maintain power generation in the minimal time of 0.2 seconds.

- The solar power system should be able to continuously maintain power generation when the voltage at the connection point falls within the band of 85% to 110% of the nominal voltage. When the voltage at the connection point falls out of the band of 85% to 110% of the nominal voltage, the solar power system should be able to maintain power generation in the minimal time of 02 seconds.

- The solar power system should cause no penetration of direct current into the distribution grid of more than 0.5% of the nominal current at the connection point.

- Solar power systems connected to low-voltage power grids shall not export reactive power to power grids and shall operate in the mode of consumption of reactive power with the capacity factor (cosφ) greater than 0.98.

- The solar power system should be equipped with protective equipment with the aim to eliminate faults and ensure safe operation of the solar power system. For the solar power system with capacity of 10 kVA or more, the customer who has request for connection should agree with the power distributor upon requirements for the protective system.

- Solar power systems shall be equipped with security devices meeting the following requirements:
  - ◊ (i) Automatically disconnect power distribution grids in case of failure occurring inside a solar power system;
  - ◊ (ii) Automatically disconnect power distribution grids in case of loss of power supplied from power distribution grids and do not generate power on power distribution grids in case of loss of electricity currently taking place on power distribution grids;
  - ◊ (iii) Do not automatically reconnect power grids due to inconformity with the following requirements: - Power grid's frequency is maintained within the band from 48 Hz to 51 Hz during the minimum period of 60 seconds; - Voltage of all phases at connections is maintained within the band from 85% to 110% of the nominal voltage during the minimum period of 60 seconds;
  - ◊ (iv) With respect to solar power systems connected to 3-phase low-voltage power grids, customers demanding connection must negotiate and agree on requirements regarding security systems with the power distribution grid operator, inter alia including at least protections specified in point (i), (ii) and (iii) of this clause, over-voltage, low-voltage and frequency protection".
- Solar power systems connected to low-voltage power grids must conform to regulations on voltage, phase balance, harmonics, flicker perceptivity and earthing mode prescribed in Article 5, 6, 7, 8 and 10 therein.

National Load Dispatch Center (NLDC) had issued the document 4304/DDQG-PT for providing detailed guidance on some key technical requirements (related to frequency response, voltage response) for rooftop solar inverters in order to meet the provisions in the Circular 39 and Circular 30 and to improve the safety and stability in the operation of the national power system. Some key technical requirements specifically applied to rooftop solar inverters are described as follows:

- The technical requirements for rooftop solar inverters connected to medium voltage grid follow the provisions of Clause 11, Article 2 of the Circular No. 30/2019/TT-BCT dated November 18, 2019 of the Ministry of Industry and Trade.
- Settings of the control and protection system of rooftop solar inverters connected to medium voltage grid must: (i) meet the technical requirements specified in Clause 11, Article 2 of Circular No. 30/2019/TT-BCT dated November 18, 2019 of the Ministry of Industry and Trade; (ii) ensure operating requirements of the equipment; (iii) ensure that rooftop solar systems have operating mode unchanged and continue maintaining the Active Power Priority mode under the fault ride through mode.

2.2.3. Regulations relating to monitoring and operation of distribution power grid

Dispatching hierarchy of national power system and hierarchy of right of control and inspection and grasp of information are stated in the Article 5 of Circular 40/2014/TT-BCT dated 5 November 2014 on stipulating the procedure for dispatching of the national power system.

Dispatching of the national power system is divided into 03 main levels:

- National dispatching level is the highest directing and dispatching level in the dispatching of the national power system. This level is assumed by the national power system dispatching center.
- Regional dispatching level is the directing and dispatching level of regional power system and is under direct management of the national dispatching level. The regional dispatching level is assumed by the North power system dispatching Center, the Central North power system dispatching Center and the South power system dispatching Center respectively.
- Distribution dispatching level:
    - ◊ The provincial distribution dispatching level is the directing and dispatching level of distribution power system in areas of provinces and centrally-run cities and is under direct management of dispatching of the respective regional dispatching level. The provincial distribution dispatching level is assumed by the dispatching unit directly under the Hanoi Power Corporation, Ho Chi Minh city Power Corporation, and the remaining 61 PCs as shown in Figure 5.
    - ◊ The district distribution dispatching level is the directing and dispatching level of districts in provinces and centrally-run cities and is under direct management of dispatching of the provincial distribution dispatching level. Depending on the scale of distribution power network of provinces and centrally-run cities, organizational structure, level of automation and actual need, the Power Corporations shall formulate the plan of establishment of district distribution dispatching level and submit it to the Electricity of Viet Nam for approval.

As above-mentioned, the RTS systems are directly or indirectly connected to the Electricity Buyer's grid with a voltage of 35 kV or less. RTS are under the provincial dispatching authority. In the Part 5 (from Article 17 to Article 19) of the Circular 40, the inspection authority and information grasping right of provincial dispatching level is:

- Control authority of provincial dispatching level:
    - ◊ The voltage on medium voltage power network in provinces and centrally-run cities, except the voltage on power network with voltage of 35 kV or less is under the control of district level as assigned
    - ◊ The medium-voltage power network in provinces and centrally-run cities, except the power network with voltage of 35kV or less under the control of district distribution dispatching level as assigned by the Power Corporation's provincial power company.

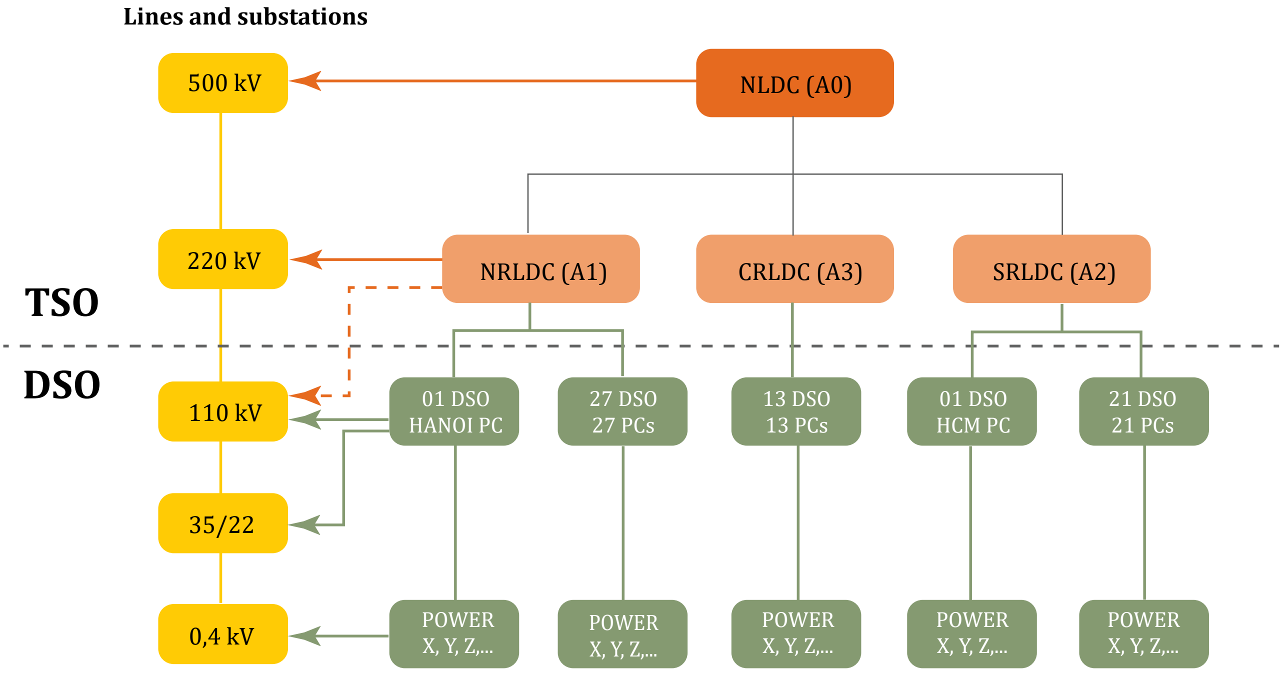
- Inspection authority of provincial dispatching level:
  - ◊ The medium-voltage power network under the control authority of district dispatching level and the power network under the management of power retailing and distributing unit and the change of structure of power network results in the change of normal operation mode of the distribution power system under the control authority.
  - ◊ The auxiliary power source of power station or auxiliary power source of small power plant under the control authority of provincial distribution dispatching level.
- Information grasping right of provincial distribution dispatching level:
  - ◊ The generating unit of large power plant connected to distribution power network results in the change of normal operation mode of the distribution power system under the control authority.
  - ◊ Power station, power network and power plant are the properties of customer connected to the distribution power network not under the control authorities of provincial distribution dispatching level.

The change of operation mode of regional power system results in the change of normal operation mode of distribition power system under the control authorities of provincial distribution dispatching level.

Article 30 of the Circular 30 obliges power generating units, among others, to "comply with operation mode and dispatching instructions of dispatching level with its control authority".

The detailed dispatching of the national power system is presented in the Figure 5:

HIERARCHICAL STRUCTURE OF LOAD DISPATCH



NLDC: National Load Dispatch Center (A0)
RLDC: Region Load Dispatch Center (Ax)
NRLDC: Northern Region Load Dispatch Center (A1)
SRLDC: Southern Region Load Dispatch Center (A2)
CRLDC: Center Region Load Dispatch Center (A3)

TSO: Transmission System Operator
DSO: Distribution System Operator
HANOI PC: Ha Noi Power Corporation
PC: Power Corporation
HCM PC: Ho Chi Minh Power Corporation

Figure 5. Hierarchical structure of load dispatch in Viet Nam

2.2.4. Regulations regarding SCADA and DMS system

To manage the SCADA system, the MOIT issued the Decision No. 55/QD-ĐTĐL dated 22/5/2017 on technical requirements for operation management of SCADA. This regulation stipulates technical requirements, connection and operation management of SCADA system in the national power system. According to the decision, the central SCADA system has an open and distributed, structure which meets some basic requirements stated in Article 5 of this Decision.

Central SCADA system is installed at dispatch levels with control authority (NLDC, RLDC, PLDC), including the following basic hardware devices:

- SCADA server collects and stores real-time data including events, status signals, measurement signals and runs SCADA applications;
- Past database server stores data of events in an order, status signals and measurement signals in a cyclical order. Past database is used for calculating, simulating and analyzing a power system;
- Application server runs the applications in EMS system or DMS system;
- Communication server connects all central SCADA systems together, connects central SCADA systems with Control Centers and RTU/Gateway devices placed at power plants or power stations;

- A screen displaying the system diagram and operational parameters of the power system;
- Man-Machine Interface (MMI) and Human-to-Machine Interface (HMI) have real-time monitoring and controlling function;
- GPS device support time synchronization on different devices in the central SCADA system;
- Other devices supporting information technology, communication and other ancillary devices.
- Specifically, SCADA data transmission channel (Article 14) includes the following basic connection interfaces:
    - ◊ V.24 or RS232 interface according to ITU-T Standard Rec V.24
    - ◊ Ethernet interface according to IEEE 802.3 Standard
    - ◊ 4W interface according to ITU-T Standard Rec G.712.
    - ◊ V.24 or RS232 interface according to ITU-T Standard Rec V.24.
    - ◊ Ethernet interface according to IEEE 802.3 Standard

The communication protocol between the SCADA system and power plants, substations, devices on the medium-voltage grid (Recloser, LBS, RMU...) is carried out in accordance with Article 15.

- Connecting the information between different function blocks inside the central SCADA system via LAN.
- Connecting the information between the central SCADA system at the national dispatch level and the systems at the regional dispatch level, which uses dedicated communication standards and IP network as transmitters.
- Connecting the information between the central SCADA system, Control Centers, RTU/Gateway devices at a power plant or a substation and the switchgears connected to SCADA signals in the power grid, which uses IEC 60870-5-104 communication standard for newly constructed power plants or power stations, and Control Centers. For the available power plants or power stations and Control Centers, IEC 60870-5-101 communication standard or IEC 60870-5-104 communication standard can be used, depending on the readiness of the transmitters (with priority given to IEC 60870-5-104 communication standard).
- Control Centers, RTU/Gateway devices at the newly constructed power plants or substations and the switchgears connected to SCADA signals in the power grid must be compatible with the communication/transmission protocol under this Regulation.
- In case of changes in the communication protocol between the central SCADA system at the dispatch level with competent control authority and those at Control Centers or the RTU/Gateway devices at power plants or power stations, the dispatch level with competent control authority is responsible for negotiating with the operation management unit in advance to adjust and ensure the compatibility of the central SCADA system, Control Centers with the new communication protocol.

- Depending on operating demand, the newly added RTU/Gateway devices at power plants or power stations can be equipped with relevant functions supporting communication protocol in its connection with smart digital devices and other monitoring devices in the power system.

Depending on operation management requirements of the power distribution unit and the power retail and distribution unit, power stations or switchgears on medium-voltage grid can connect to the central SCADA system at the dispatch level with competent control authority.

Based on the requirements of operation management, the DMS system can be equipped with one of the following applications:

- The graphic interface allows a clear display of the status of electricity lines, transformers and other devices on the power distribution system.

- Monitoring, assessing and identifying the changes in the configuration and the distribution system diagram.

- Analyzing and optimizing the operation of the power distribution system with the function of assisting dispatchers to monitor, control, analyze, plan and optimize the operation of the power distribution system. This application performs the following key functions:

    ◊ Using grid-connected configuration and real-time operational data from the central SCADA system and customers' information to estimate active power and reactive power at load nodes in the distribution grid;

    ◊ Analyzing load flow: Using the function of calculating current intensity, voltage, power factor, phase angle, active power and reactive power of each device in the power grid to identify the cases of possible overloads or voltage oscillations in the power distribution grid;

    ◊ Calculating short circuits simulated for different areas in case of failure in the power distribution grid;

    ◊ Managing voltage, reactive power and load: provide solutions for installing capacitors and tap changers to control reactive power and improve the quality of voltage in the distribution grid;

    ◊ Quickly locating and isolating possible faults, and identifying the switchgears which can be used for restoring power supply for isolated areas;

    ◊ Reconfiguring grid-connected distribution system in consideration of actual operating conditions: (i) identifying changes (switching on/off) in the distribution grid and calculating, reallocating load between outgoing feeders to reduce power distribution losses; (ii) determining the conditions enabling optimal operation of the power distribution system within allowable limits.

    ◊ The load shedding function supports the dispatchers in load shedding and recovery in the distribution grid.

- Outage management system (OMS): Controlling and handling outages in a timely and efficient manner. Based on operation and maintenance plan, information provided by customers, and real-time data from the central SCADA system, the OMS can quickly identify the elements in trouble and affected areas in order to work out solutions for limiting outages, fixing and restoring power supply as quickly as possible.

- Simulation-based training on the operation of the power distribution system is equipped with the following basic functions: (i) simulating the power system model so that the dispatchers can practice operating the power distribution system in normal operating conditions and in case of emergency; (ii) testing and simulating the actual operation scenarios, piloting power distribution system restoration plans, evaluating efficiency and piloting the applications of the DMS system in a simulated model.

2.2.5. Fire protection regulations for rooftop solar power systems

The Fire and Rescue Police Department (Ministry of Public Security) (the fire protection department) has issued Dispatch No. 3288/C07-P4 dated 8 September, 2020 to the Police of the provinces/cities directly under the government guiding the design appraisal and approval of rooftop solar power systems as below:

- The fire protection design for RTS systems installed on works under Appendix IV of Decree No. 79/2014/ND-CP (which has been replaced by Appendix V of Decree No. 136/2020/ND-CP dated November 24, 2020), must obtain appraisal.

- For RTS not subject for appraisal fire protection design, it should be:

  ◊ Do not install solar panels above rooms with fire hazard class A, B, C as well as other rooms that have the ability to accumulate gases and fire dust during operation; limit the placement of panels on storage rooms or rooms with large volumes of flammable substances; do not install rooftop solar power systems on buildings with high risk of fire, explosion, and toxic such as petroleum, gas, explosives warehouse, chemical warehouse ...

  ◊ The layout of panels, lines and equipment of the solar power system must not shield the booster fans, must not interfere with access to the pumping station (in case the pumping station is located on the roof) and other fire prevention systems of the building;

  ◊ When installing solar panels and other equipment of the roof solar power system, must calculate the load affecting the roof structure under normal and in fire conditions; do not install panels on roofs made of burning materials or have a finishing material that is a flammable substance;

  ◊ Inverter and the closed cabinets, wire cabinets... when arranged in the house must be arranged in a separate room/space for monitoring and protection; do not to arrange fire substances around this area and there must be a fire prevention solution with other areas of the building. The equipment of the system must be grounded in accordance with regulations.

◊ The building must arrange roof exits through stair chambers, fire extinguishers, or trapdoors; the panels should be arranged on the roof side with access for fire engines to approach;

◊ The layout of the device on the roof must ensure accessibility, ability to move from the roof exit to each group, and battery range.

◊ Solar power systems must be equipped with emergency break-off equipment. This device needs to be arranged both in the position of the inverter and the location of the cutting cabinet. At these locations, instructions and operation procedures must be listed;

◊ In areas near the roof access, there must be a layout of the roof panels and system connection diagrams to aid the disconnection of the panels on the roof when there is a problem and serve firefighting and prevention work.

◊ The rooms in the house that contain equipment from the roof solar power system such as inverter, closed cabinets... must be equipped with firefighting and prevention equipment and systems as required by the current firefighting regulations and technical standards. The selection of firefighting systems and agents must be suitable for the equipment and ensure fire prevention against fire of electricity-carrying equipment.

2.2.6. Construction safety requirements

Regarding technical instructions related to construction safety when installing rooftop solar power systems with a capacity of no more than 1 MW, follow the instruction manual of construction technology HDKTXD: 2020 of the Vietnam Institute of Building Science and Technology (IBST). This was announced by the Ministry of Construction in Official Dispatch No. 6242/BXD-KHCN dated December 28, 2020.

2.2.7. Environment requirements for RTS system

According to Decree No. 40/2019/ND-CP dated May 13, 2019 amending and supplementing a number of articles of the decrees detailing and guiding the implementation of the Environmental Protection Law, with small-scale rooftop solar power projects of less than 50 hectares, the investor is not required to carry out procedures for environmental impact assessment as well as environmental protection plans. However, they still have to comply with the provisions of the law on the management of normal solid waste and hazardous waste according to existing regulations.

The implementation of solar power projects and the development of clean and renewable energy by investors, and the recovery of PV panels by manufacturers and distributors after the end of their useful life for recycling, reuse and reducing waste are activities that are encouraged and in accordance with the State's policy on environmental protection specified in Clause 3, Article 5 of the Law on Environmental Protection 2014 (Clause 4, Article 4 of the Environmental Protection Law of 2020, takes effect from January 1, 2022).

According to the provisions of Article 55 of the Environmental Protection Law of 2020 (effective from January 1, 2022), organizations and individuals who manufacture and import products and packages containing hazardous substances that cause difficulties for the recycling, collection and treatment process must make financial contributions to the Vietnam Environmental Protection Fund to support waste treatment activities and leave it to the Government to spell out the details of this content. Accordingly, in the coming time, the Ministry of Natural Resources and Environment will advise the Government to develop a Decree guiding the implementation of the Environmental Protection Law of 2020, which will propose putting solar panels on the list of products that manufacturers and importers must recall and recycle.

Currently, the Ministry of Natural Resources and Environment is assigning the General Department of Environment the prime responsibility for developing the scientific and technological thesis "Research on scientific basis, practice and propose solutions to solar panel management and treatment." This is the basis for the consideration and promulgation of Technical Guidelines on treatment and recycling of waste from PV panels in Viet Nam.

2.3. Challenges and opportunities of RTS integration and motivation for remote monitoring and control

2.3.1. Current challenges faced by DSOs and TSOs associated to RTS feed-in

High penetration of RTS has made some changes to the management and operation of the distribution grids. Before the integration of RTS into the power system, distribution-level dispatching agencies mainly focus on planning the way of receiving electricity from 110 kV and 220 kV substations (receiving one-way power flow from higher voltage to lower voltage level) to ensure electricity supply to customers. However, in the current state, they have to additionally calculate, exploit, and make plans on how to operate RTS power sources during the daytime and allow medium voltage power grids to carry electricity in two ways. Therefore, the duties of distribution-level dispatching agencies significantly increase in carrying out load forecast, RTS forecast, calculating how to mobilize RTS power sources to balance and stabilize the distribution grids, and dispatching the mobilized RTS sources, etc.

The distribution grids operated by provincial and city power companies are added various elements such as line segments, transformers and substations of investors that connect to and utilize the distribution grids (probably more than a dozen elements added to 110 kV grid, and hundreds of elements added to medium voltage grid). Thus, the operation of the local distribution grids with the integration of assets of many different investors also becomes very complicated in respects of operation coordinating, troubleshooting, maintenance and assets repairing.

110 kV grid-connected VRE power plants have operational shift/ shift-based on-duty personnel (including remote control centers), most of which are SCADA connected and virtually controlled by National and Regional Load Dispatch Centers. For the low-voltage grid-connected RTS systems, which are often associated with the system owner's electricity usage, the owners must always pay attention to ensuring sufficient electricity for their self-consumption and no impact from the power companies on their system, because this system was connected behind the meter. For a large number of medium-voltage grid connected RTS systems, which most system owners do not use electricity on the spot but sell electricity to power companies, they either do not have specialized staff members to take over the system operation or do not connect their system to SCADA system which make the dispatching of their generated capacity difficult.

Like other power sources, RTS also needs to be increased (if operating at a reduced output) and reduced capacity, adjusted voltage and so on to balance with the loads and the technical constraints of the electrical system to ensure the safe operation of the system. These functions can be performed through inverters, some of which need to be monitored to ensure the proper automatic operation (such as adjusting voltage, operating and stop mode, etc.); the function of increasing and decreasing the capacity can only be controlled through the remote-control system, but the RTS systems are not legally regulated to connect with any control system so these functions cannot be executed automatically remotely.

In recent years, to avoid overloading the power grids, the mobilization of VRE and RTS capacity has been calculated weekly by the National Load Dispatch Centre (NLDC/A0). After receiving the calculated results of the maximum dispatchable capacity of RTS, NLDC would notify the power corporations so they could allocate the maximum dispatchable capacity to the power companies according to the existing RTS percentage managed by the power companies. From the allocation of maximum dispatchable capacity of power corporations, the power companies shall allocate proportionally in percentage to the RTS systems available and notify RTS owners to properly control in accordance with the given dispatched capacity. Some RTS systems can be increased/decreased with capacity by remote control, yet some others needed to be performed on site. During COVID-19, due to social distancing, it was difficult to control and monitor the increase/decrease of capacity on the spot.

In the days with low demand and partial grid overload, it is necessary to redispatch the generating capacity of power plants including VRE. VRE power plants are allowed to automatically adjust their power generation capacity through the AGC (Automatic Generation Control) function of SCADA systems, so they can control the transparency and fairness of the system. Monitoring the implementation of capacity adjustment of RTS systems is even more difficult in ensuring compliance with the principles of moderation, fairness, and transparency among investors.

2.3.2. Assessing opportunities for implementing remote monitoring and control

Overview of capabilities of existing AMR meters

Currently, there are electronic meters of the following companies being used in Viet Nam including Elster, Landis&Gyr, Gelex, Emec, Vinasino, Huu Hong, Psmart, CPCEMEC... These meters meet the technical standards issued by EVN under Decision No. 103/QD-EVN dated June 21, 2017.

The current implementation of AMR system by corporation until 2021 is as table below.

Table 4. Implementation of AMR system by corporation

No.	Power Corporation	AMR Roll-Out (%)
1	EVNNPC	80%
2	EVNCPC	92%
3	EVNSPC	42%
4	EVNHANOI	100%
5	EVNHCMC	82%

(Source: Power Corporation, 9/2021)

Most medium-voltage grid connected RTS systems have been equipped with multifunctional electronic meters for the purpose of measuring. These meters measure and record many parameters, events and transmit to the metering data storage of the power corporations. The key parameters in the metering system being measured and recorded are:

- Measuring the active power in two ways, i.e. power delivered and received; measuring the reactive power in two ways of delivery and receipt; recording these parameters every 30 minutes (30-minute interval) to form load profile of 48 cycles per day.
- Record max and min power capacity on a daily basis. Record the events of power outages, phase shortages, phase imbalances...
- It is also possible to use the method of continuous access to meter (by an interval of 15 minutes, 30 minutes, 60 minutes) to monitor the voltage, current, instantaneous active and reactive power (P, Q) of the RTS system.

- Using data analysis tools in the metering system of power corporations that can perform the following tasks:

  ◊ Make a classification list: RTS systems which only sell electricity to the grid; or RTS systems for self-consumption and selling of electricity to the grid at different rates.

  ◊ Customers who comply or fail to comply with the dispatch command in mobilizing RTS capacity.

  ◊ Provide the ratio of electricity output sourced to the grid/installed capacity of the RTS system on a daily, weekly, monthly and annual basis from which to assess the level of equality in capacity dispatching among investors in a province or city; between provinces and cities; among power corporations.

  ◊ Provide comparison data for forecasting models; actual historical data for machine learning, thereby adjusting the forecast model more accurately

- For RTS, EVN installs two-way electric meters and transmits data to the CMIS system via GPRS/3G. Currently, Power Companies monitor the operation of RTS systems through two-way meters from App Meter software, CMIS programs, distribution systems and remote measurement data analysis - MDAS

Overview of existing SCADA/DMS of Power Corporation

As above-mentioned, in order to manage the SCADA system operation, Electricity Regulatory Authority of Vietnam (ERAV) under the MOIT issued Decision No. 55/QD-DTDL dated May 22, 2017 on the promulgation of regulations on technical requirements and management of the operation of SCADA system. However, there is no definition of mini-SCADA or Micro-SCADA systems as well as the scale of these systems. In addition, this regulation does not specify what types of signals should collect for forecasting (e.g. weather...) and which signals serve the operation (voltage, frequency, power capacity, capacity...).

The Decision No. 55/QD-DTDL so far only stipulates technical requirements for the central SCADA system, SCADA/EMS, SCADA/DMS and the signals to be collected to serve the operation such as: signal of the generator unit, signal of the busbar, signal of the line, signal of transformers, signal of circuit breaker and disconnect switches.... Therefore, it is necessary to consider and supplement the signals to be collected for the RTS system.

The current status of SCADA/DMS system of 05 Power Corporations is described as follows:

EVNNPC SCADA/DMS system

EVNNPC is responsible for the management, operation and assurance of electricity supply for 27 northern provinces and cities. EVNNPC manages a total length of over 67,620 km of medium voltage lines (35 kV, 22 kV, 10 kV and 6 kV) (of which 35 kV lines account for over 66.54%). The total capacity of medium voltage distribution transformers is over 12,862 MVA.

EVNNPC has operated 27 control centers and is remotely controlling 263/263 110 kV substations (>90% unmanned 110 kV substations) and about 3354/8740 (38.4%) equipment on medium voltage grid (Recloser/LBS/RMU).

EVNNPC has provided the central control software Spectrum Power 5 (Siemens/Germany) for 27 provincial/city power companies and is implementing functions to support medium-voltage grid (DMS) management such as determining and isolating incidents, load resetting, capacity storage calculations, short-term load planning, power system assessment and estimation, dynamic coloring by voltage hierarchy, etc.

EVNHANOI SCADA/DMS system

EVNHANOI manages a total length of over 9,000 km of medium voltage lines (35 kV, 22 kV, 10 kV and 6 kV) (of which 22 kV lines account for 70,0%). The total capacity of medium voltage distribution transformers is over 13,102 MVA.

EVNHANOI has operated 01 control center and is remotely controlling 49 substations 110 kV (100% unmanned 110 kV substations) and about 465/10,617 (4.5%) equipment on medium voltage grid (Recloser/LBS/RMU).

EVNHANOI is equipped with ABB's SCADA system. EVNHANOI's distribution network management system (DMS) is a module integrated into ABB's SCADA system, consisting of a set of applications designed to monitor and control the entire distribution network efficiently and reliably. EVNHANOI is implementing the main DMS functions: Load Calibration: (i) calculation the parameters at the time of pre-establishment including current, voltage, power at all nodes of the power grid, (ii) load flow calculation, (iii) calculation of the parameters at the specified mode at a specific time, mainly the current and pressure at every node of the power grid; Short circuit analysis: (i) Short-circuit line calculation, locates the problem based on the basis of the problem distance calculation and the data set indicating the problem; (ii) integration voltage-var control: Voltage control and power coefficient on the grid.

EVNCPC SCADA/DMS system

EVNCPC is responsible for managing operations and ensuring electricity supply to 13 provinces and cities in the Central and Central Highlands. EVNCPC grid has more than 763 medium-voltage lines (35 kV, 22 kV) with a total length of over 28,887 km (of which, 22 kV lines account for a large proportion of 93%). Total medium-voltage distribution transformer capacity is above 5,429 MVA.

EVNNPC has operated 13 control centers and is remotely controlling 134 substations 110 kV 100% unmanned 110 kV substations) and about 3,291/3,765 (87.6%) equipment on medium voltage grid.

EVNCPC is equipped with SCADA/DMS software of Survalent (Canada), 07/13 SCADA systems are equipped with DMS system and are being deployed. EVNCPC has applied the function of automatic incident detection, location, isolation and restoration of power supply (FLIRS) to the 22 kV power grid of Da Nang city (DAS), researched the plan to calculate the online capacity trend for 1-2 routes, and performed data sharing links between MDMS software and SCADA/DMS.

EVNCPC is implementing procedures to continue equipping DMS for 04/13 Power Companies: Quang Binh, Phu Yen, Kon Tum and Dak Nong.

EVNHCMC SCADA/DMS system

EVNHCMC is responsible for managing operations and ensuring electricity supply to Ho Chi Minh City. The medium-voltage distribution grid system is 01 voltage level (22 kV) with more than 770 lines and a total length of over 7,154 km. The total capacity of the transformers distributed is above 13,234 MVA.

EVNHCMC has operated 01 control center and is remotely controlling 56 substations 110 kV (100% unmanned 110kV substations) and about 1,871/6841 (27.4%) equipment on medium voltage grid (Recloser/ LBS/ RMU).

EVNHCMC is equipped with Alstom's SCADA system (now GE) that provides the full range of features of the SCADA system as well as is equipped with advanced distribution grid management (ADMS) functions including: load flow calculation, bus load allocation, Short circuit calculation, FDIR, power grid operation optimization restructuring, (OMS) power outage management...

EVNSPC SCADA/DMS system

EVNSPC is responsible for managing operations and ensuring electricity supply to 21 southern provinces and cities (except Ho Chi Minh City) with a total line length of more than 61,555 km (of which, 22 kV lines account for a large proportion of 99.5%). The total medium distribution transformer capacity is more than 17,881 MVA.

Control center: SCADA's central system EVNSPC uses spectrum (Siemens) software with DMS function, sharing consoles for DSO of 20 provinces to serve as control centers (model of technical infrastructure focus and decentralization of monitoring and control) and have built single-line operation schemes for power grid 110 kV and 22 kV according to the management area of each province.

Currently, EVNSPC has also into operation 20 control centers in the Moderation Room of 20 affiliated PCs. The SCADA (Spectrum Power 7) system is connecting and controlling 205 110 kV substations (100% of unmanned 110 kV substations) and over 1024/5547 (18.6%) of devices on the medium voltage grid.

Dong Nai PC has been equipped with Survalent's SCADA/DMS system. SCADA/DMS system is connecting, remotely controlling 27 substations (100% unmanned 110 kV substations) and 201/1,081 (18.6%) devices (Recloser/LBS/RMU) on medium-voltage grids. Dong Nai PC has applied the functions of the DMS system including: Monitoring, evaluating and identifying changes in configuration, grid-ending diagram of the network connectivity analysis; Quickly identify the location of the problem, the appropriate isolation point, and identify workable closed-off devices to restore power supply to isolated grid areas (FLISR); Simulation of operation of distribution power system has the following basic functions: (Operator training Simulator).

Table 5. Current status of SCADA/DMS and connection RTS system

No.	Power Cooperation	SCADA/DMS system	Number of Remote controls 110kV substation	Number of controlled devices on the medium voltage grid
1	EVNNPC	27	263	3354
2	EVNCPC	13	134	3291
3	EVNSPC	21	230	1024
4	EVNHANOI	1	49	465
5	EVNHCMC	1	56	1871

(Source: Power Corporations, 9/2021)

2.3.3. Overview of capabilities of existing inverters

Currently, RTS systems in Viet Nam used inverters made by SMA, Huawei, Solis, Growatt, Goodwe, ABB, Fronius, SolarEdge, Omnik, INVT,...

Inverter is the heart of solar farms and RTS systems. The application of electronic power technologies and the most advanced micro-controller technologies have enabled inverter manufacturers to equip their MV grid connected inverters with many good functions to support the operation of distribution grid system.

Inverter working modes

Through inverters, it is possible to control the active power P and reactive power Q of RTS sources. Inverters usually have two main working modes:

- Steady state: This is the control mode of the inverter under normal operating power system conditions. In the steady state, the active power (P) will be fed to the grid by the inverter depending on solar irradiation; the reactive power (Q) will be injected to the grid depending on the reactive power control mode installed in the inverter. Typically, the inverter will have two main reactive power control modes as follows:
  - ◊ Q Mode: Control mode based on set value of reactive power (Q), depending on the capacitor capacity and reactor installed in the inverter.
  - ◊ Power Factor Control: control mode based on power factor (cosφ).
- Fault mode (FRT- behavior): is the control mode of the inverter when a fault occurs in the power system. For fault mode, the inverter may have the following responses depending on the settings and configuration of the inverter:
  - ◊ The inverter will automatically reduce the active and reactive current to zero. Once the fault has been cleared, the inverter will automatically restart (Zero Power Mode).
  - ◊ The inverter will prioritize generating active current to the grid during a fault to support grid frequency while reactive current may decrease according to inverter capacity (Active Power Priority).
  - ◊ Inverters will prioritize generating reactive current to the grid to support grid voltage during a fault while active current may decrease according to inverter capacity (Reactive Power Priority).

Technical inverter responses.

RTS inverter connected to medium voltage meet technical requirements mentioned in Part 11, Article 2 of Circular 30/2019/TT-BCT dated 18/11/2019. The main technical requirements for RTS inverters are as follows:

- Required minimum time length for maintenance of power generation at RTS system in proportion to frequency bands of electricity systems as low as 47.5 Hz and as high as 52 Hz still maintain power generation time is minimum from 1 minute to 30 minutes as prescribed, depending on the frequency range.

- When the electricity system's frequency is greater than 50.5 Hz, wind and solar power plants may reduce active power on the comparative slope of droop characteristics within the steep gradient range of between 2% and 10%. The set value of the slope of droop characteristics is calculated and determined by the dispatch level vested with controlling rights.

- Voltage control mode and reactive power: should consider and study the applying mode of control according to power factors (cosφ) for limitation deviation of voltage. The adjusted value is calculated for each area.

- RTS system which are, at any time, connected to transmission grids must be capable of maintaining generation of power commensurate with the voltage band at the connection point within the following specific time points: if voltage is less than 0.3 p.u, minimum maintenance time will be 0.15 second or if voltage ranges from 1.15 p.u to under 1.2 p.u, RTS system must maintain power generation for 0.5 seconds.

- Requirements for response of inverters in the failure: As above-mentioned, in the grid failure, the inverter can operate in 3 modes. The selection of mode and calculation of parameter settings for each mode need to be studied and calculated to achieve the best effect.

- Requirements for response of inverters after facing failure: if the failure lasts longer than the required minimum time, the inverter will stop working.

Therefore, the inverter must be installed with the corrective parameters to only restart and transmit power to the grid no earlier than the required time to maintain the grid in the prescribed frequency and voltage range, ramp rates are also installed to comply with regulations.

Currently, new RTS with a capacity above 500 kW must follow the requirements stated in the document No. 4304/DDQG-PT dated October 11, 2021 on "Guiding technical requirements for solar power inverters".

The ability to integrate inverters' monitoring and control systems

- Most commercial inverter manufacturers already produce inverters that are capable of connecting to remote monitoring and control systems.

- RTS systems often have multiple inverters connected in groups to a logger. The installation, monitoring, control of inverters can be through this logger. Performed on-site through HMI software, done remotely through connection to the monitoring center using 3G and 4G public telecommunications systems. Developers use the manufacturer's cloud-based applications for smartphones to real-time monitor their RTS system performance parameters.

- A small number of RTS systems have been connected to SCADA by power companies (due to regulations that are not required to connect).

- In Viet Nam, there are units researching and developing systems to connect monitoring and remote control of EIA systems such as Viettel - VCC, Nichietsu, ATS JCS ....

2.3.4. Smart meter rollout (possible use for RTS monitoring and control)

The deployment of the AMI system will lead to a huge amount of data being collected. This big data needs to be analyzed to produce useful results that can assist grid operators in improving the operation and maintenance of the grid. Furthermore, power distribution units can use data analytics to better understand customer usage behavior, conventional consumption, strengthening the grid, and the need to replace your assets.

Viet Nam piloted the AMI system (Tatung and Trilliant solution) at EVNHCMC in 2015, specifically as follows:

i. 184 customers of Gia Dinh Power Company;

ii. 60 smart meters

At that time, Viet Nam had not developed the electricity market and renewable energy sources, the cost of purchasing AMI system was expensive and not highly efficient, so this has been stopped so far.

Currently, EVN is reviewing the roadmap for smart grid development including AMI system. The implementation of the AMI system involves equipping smart meters, evaluating and selecting technology for transmission, management and exploitation of big data, deployment costs, pricing mechanisms, guidelines and related regulations. So far, there is no policy and roadmap for implementation.

2.3.5. Key findings from previous pilot projects in Viet Nam

Up to now, there is no mandatory regulation to connect RTS systems, but there are now a handful of RTS systems that have been connected to SCADA by power companies.

Some customers can control the RTS system through the inverter provider's software. In Viet Nam, a few companies have been researching and developing the monitoring and remote control of connected RTS systems such as Viettel - VCC, Nichietsu, ATS JCS .... Among solutions for monitoring and remote control of connected RTS, RTS system data is managed by companies. Therefore, it is also necessary to consider solutions to protect the rights and data of RTS investors.

It is necessary to also consider virtual power plant solutions to connect and manage the operation of solar power systems that increasingly penetrate the grid.

3. Overview of international experience and good practices for remote monitoring and control of RTS

In this chapter, Section 3.1 will summarize the findings of the review of requirements and practices for remote control and remote monitoring of rooftop solar units for selected countries: Germany, Australia, USA, Italy and Thailand. At the end, the key findings of all countries will be compared in an overview table. The reviewed countries were selected due to having reached high shares of rooftop solar (above 10% of total generation installed capacity) and being international references in technical requirements for rooftop solar and in its development. Thailand on the other hand has reached only 1% rooftop solar share of total installed capacity and was chosen due to being for many years reference in Southeast Asia for renewable energy development.

In Section 3.2, an overview of the different solutions and technologies available today that can be used to implement remote monitoring and remote control of RTS is presented.

3.1. Overview of selected countries' experience

3.1.1. Germany

Motivation

In Germany, the 2020 PV capacity increase target of 2.5 GW was almost doubled, with installed PV capacity increase reaching over 4.9 GW. By the end of 2020, the total installed PV capacity was 54 GW accounting for 25% of the total installed generation capacity. On sunny days, PV generation can already cover two thirds of Germany's electricity demand. The German renewable Energy Sources act (EEG) has set an interim target for 2030 of 65% share of renewable energies (RE) of the gross electricity consumption and sets the PV expansion target to 100 GW. To achieve this, a PV capacity increase of at least 5 GW will be needed each year [1].

Figure 6 shows the share of capacity and number of PV installations as a percentage of cumulative installations for the year 2020.

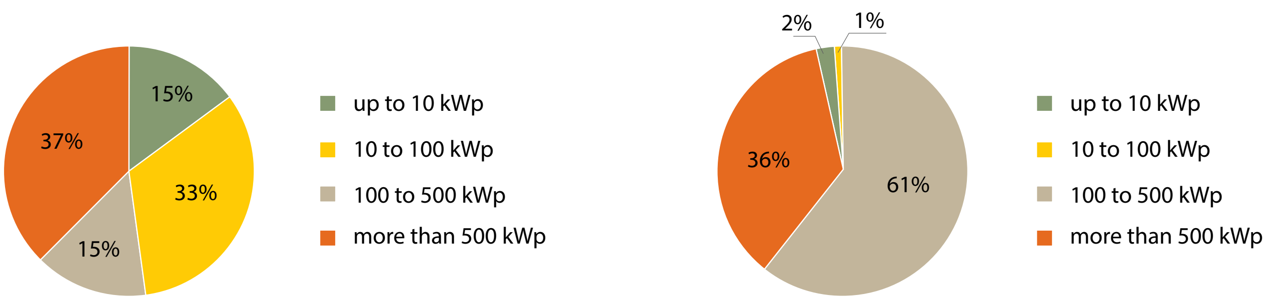


Figure 6. Share of PV systems by cumulative capacity (left) and cumulative numbers (right) [2]

Since a 2012 amendment of the EEG, PV feed-in management schemes must be applied to all PV systems connected to the low voltage grid. Depending on the installed capacity, this would entail limiting active power feed-in to 70% of installed capacity or enabling Distribution System Operators (DSOs) to remotely curtail PV systems in the event of grid congestion or faults.

Requirements

According to section 9 of Germany's renewable energy act of 2017 (EEG) [3]:

- All PV systems with installed capacities over 100 kWp must be equipped with technical equipment with which the network operator can remotely monitor current feed-in and reduce the feed-in at any time in the event of network overload (subsection 1).

- PV systems with installed capacity between 30 kWp and 100 kWp are only required to be equipped with technical equipment with which the network operator can remotely reduce the feed-in at any time (subsection 2, sentence 1).

- PV systems with installed capacity up to 30 kWp are required to either have the active power feed-in limited to 70% of the installed power at the point of connection between the system and the grid or facilitate remote feed-in reduction (subsection 2, sentence 2).

As of 2019, around 25.7 GWp is regulated according to subsection 1; 8 GWp according to subsection 2; 3.5 GWp is regulated with the 70% feed-in limit and 11.9 GWp remains unregulated [4]. A reform of the renewable energy act has taken effect since January 1st, 2021. According to this reform, the threshold of 30 kWp is reduced to 25 kWp for new rooftop PV systems. Otherwise, all previous specifications remain in place [5]. As long as the Federal Office for Security and Information Technology (BSI) has not confirmed that the technical possibilities for a holistic intelligent measuring system are available, new systems do not have to be equipped with a smart meter gateway. In this case, remote feed-in control would be typically done via Radio Ripple Control (RRC).

Once it has been confirmed that the technical possibilities for equipping the system with a smart meter gateway are available, the following rules would apply:

- New systems up to 7 kWp must have the active power feed-in reduced to 70%.

- New systems larger than 7 kWp must be equipped with facilities that enable the use of a smart meter gateway, which allows the network operator to call up the actual feed-in and perform feed-in reduction if necessary.

Approach

Radio Ripple Control

For systems with an installed capacity between 25 kWp and 100 kWp, Radio Ripple Control (RRC) has been widely used by grid operators to reduce PV feed-in remotely. As shown in Figure 7, Radio ripple control systems primarily consist of an operating station, central computer, long-wave transmitter, and radio ripple control receivers. The user (grid operator) creates commands at the local operating station. The commands are sent to a central computer, which passes the commands to the transmitter. The main transmission protocols used for addressing radio ripple control receivers are Versacom and Semagyr. Feedback via this communication channel is not possible.

The radio ripple control receiver can be connected directly to inverters that support digital inputs. Otherwise, radio ripple control receivers are connected to another intermediate device (depending on inverter manufacturer). This device is usually a power management controller which would convert the digitally coded signals from the radio ripple control receiver into a control command for the linked inverter(s). All inverter brands sold on the global market are generally capable to be controlled via RRC.

Controlling PV systems through RRC is considered to be a low-cost solution for DSOs, as it utilizes Germany's existing long-wave radio infrastructure. However, this method does not allow DSOs to send commands to individual PV systems, but rather signals sent are received and acted upon by a group of systems at a time. This could result in curtailing more PV systems than necessary.

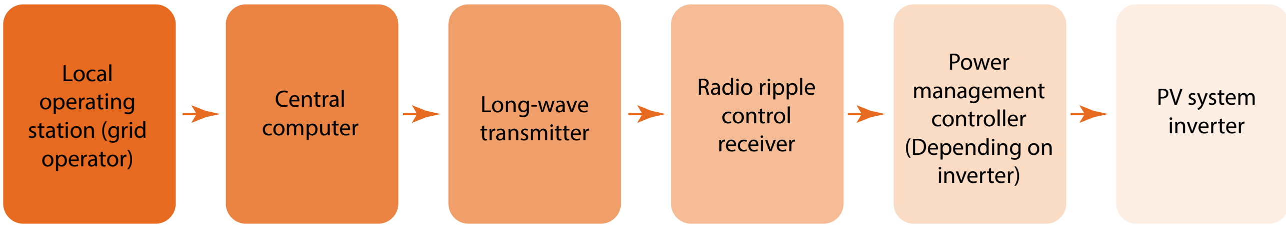


Figure 7. Radio Ripple Control Information Transfer Process

Remote control of PV systems through RRC imposes additional costs to PV system owners. The owners must pay for the radio ripple control receiver and, if applicable, the power management controller. However, the costs are comparatively low and do not pose a major impact on the financial feasibility of the PV systems.

Radio ripple control receivers have an internal memory in which the switching program for the device is stored. For PV systems with installed capacity between 25 kWp and 100 kWp (30 kWp and 100 kWp before the implementation of the new regulation), feed-in is reduced in steps. Typically, a 4-step control scheme is implemented. For this purpose, four potential-free changeover contacts are activated on the radio ripple control receiver. These four relays represent the power levels 100% (full feed), 60%, 30% and 0% (no feed). Figure 8 shows an example of how RRC receivers can be wired to achieve a 4-step control scheme [6].

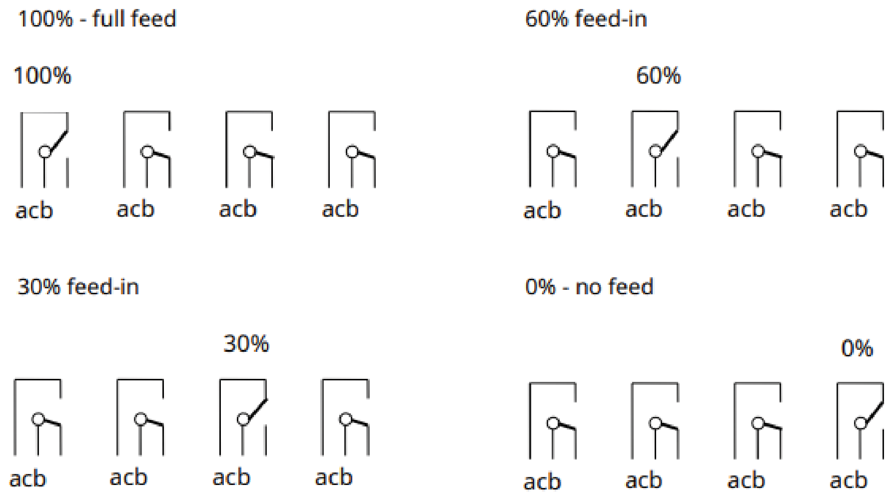


Figure 8. Wiring example of a radio ripple control receiver with 4 relays [6].

For smaller PV installations below 30 kWp (25 kWp after new regulation implemented) which are controlled via RRC, a 2-step control scheme is typically used. In this case, two relays would be assembled on the radio ripple control receiver representing power levels of 100% (full feed) and 0% (no feed).

For systems with installed capacity greater than 100 kWp, the actual feed-in must be recorded and monitored in addition to remote curtailment. The method in which the system is remotely monitored and controlled is to be decided by the DSO. An additional method to radio ripple control is described next.

"Grid-Modul" Control (using cellular network)

Netze BW, a distribution system operator for the state of Baden-Württemberg, uses a control system called the "Grid-Modul" (see communication infrastructure in Figure 9). The control system was developed in cooperation with the measurement technology manufacturer Landys+Gyr. This control system consists of the Grid-Modul (responsible for control functions) and a Synchronous Modular Meter (SyM2 Meter). The SyM2 is a load profile meter intended to provide near real time feed-in data. The control system can be connected to the DSO's Supervisory Control and Data Acquisition (SCADA) system and German remote meter reading (ZFA) using the Smart Message Language protocol (SML)[5] with the help of an Internet Protocol (IP) Telemetry. Communication is bidirectional and takes place through Global System for Mobile Communications (GSM)[6]/General Packet Radio Service (GPRS)[7]. Similar to RRC receivers, the control system allows PV systems to be curtailed in steps of 0%, 30%, 60% and 100% using the Grid-Modul's digital outputs [7] [8].

5 SML is a client-server communication protocol for electricity meters used to transmit measurement data, firmware updates and command signals.
6 GSM is a globally accepted standard for cellular communication.
7 GPRS is an extension to GSM and allows packet data to be sent and received across the GSM network.

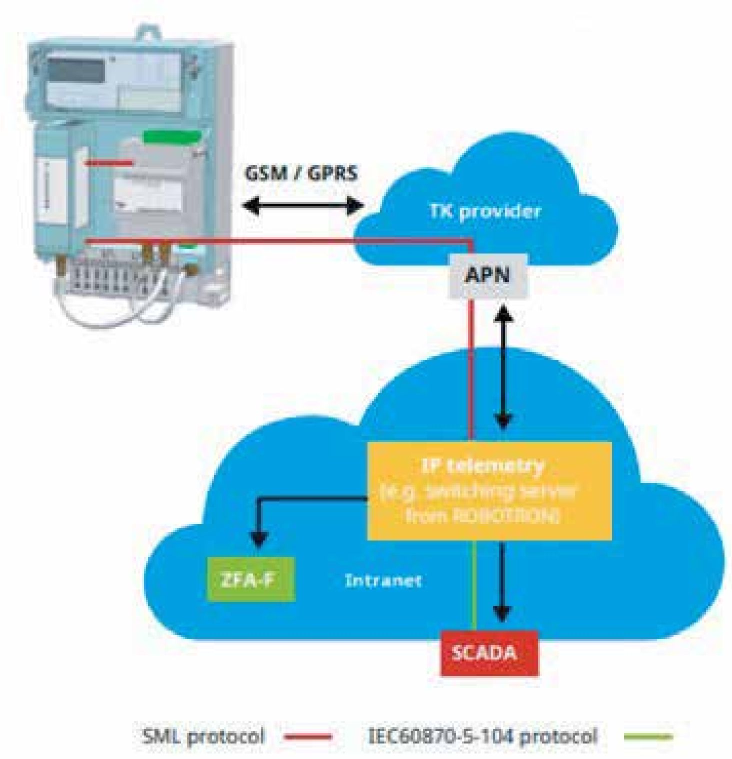


Figure 9. Grid-Modul communication infrastructure [8]

The main advantage of such an approach compared to RRC is that individual PV systems can be controlled, whereas RRC only allows several systems to be controlled at the same time, which could lead to unnecessary PV curtailment. However, this approach adds larger additional costs for both, PV systems owners and DSOs, and increases system complexity in comparison with RRC.

Regulations

Grid system operators must ensure that the largest possible share of electricity from renewable energy sources and Combined Heat and Power (CHP) plants is purchased. In the event that PV systems must be curtailed, the grid system operator must inform the system owner, at the latest one day in advance, of the expected point in time, duration and scope of curtailment. After the event, PV system owners must be provided with information on the actual points in time, scope and duration of curtailment without delay. On request, grid system operators must provide proof of the need for curtailment within four weeks after the request.

According to the EEG, PV system owners must be compensated by grid system operators for 95% of their revenue losses due to curtailment of up to 1% of their annual PV energy output. For any losses incurred above 1% curtailment, 100% of revenue losses must be compensated[8].

8 Energy curtailed is estimated using irradiation measurements during the curtailment period and comparing it to the power output of a comparison period with the same irradiation, where no curtailment occurred

3.1.2. Australia

Motivation

As of September 2021, there are over 2.96 million PV installations in Australia, with a combined capacity of over 23.5 GW of which, 15.4 GW is from RTS installations[9]. Since 2017, installed PV capacity has been growing rapidly with an average annual capacity increase of 4.5 GW, as shown in Figure 10.

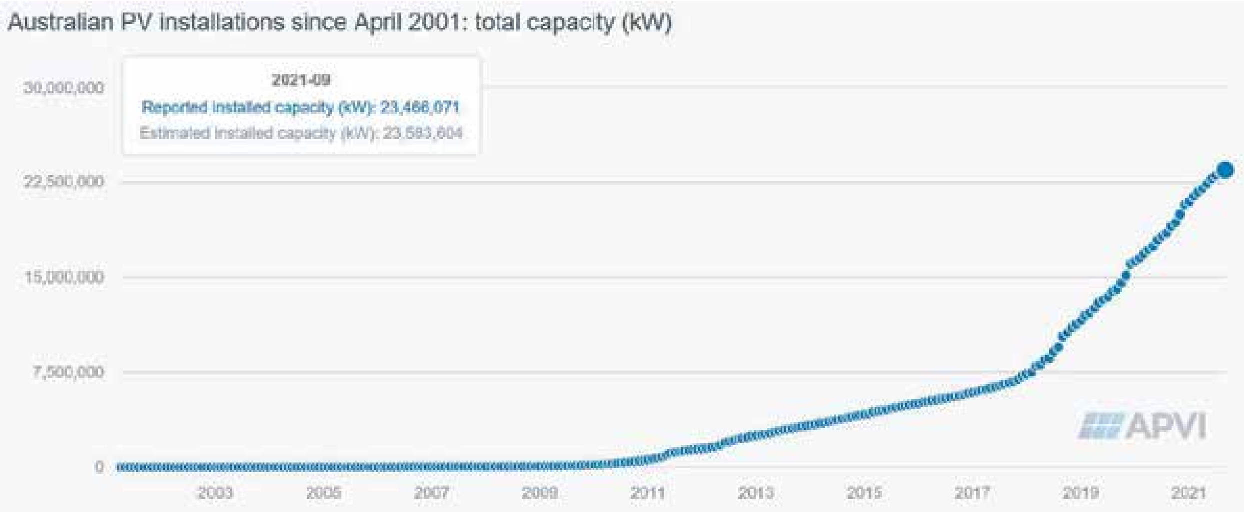


Figure 10. Installed PV Capacity Growth in Australia until April 2001 [9]

According to Australia's 2021 emission projections report, the share of renewables in Australia is expected to reach 61% by 2030 with a total installed PV capacity of 42 GW (39 GW of which is small scale with installed capacity less than 100 kWp). South Australia will source 96% of its electricity from renewables (29% from RTS [10]), while in Western Australia 45% of its electricity will be sourced from renewables [11].

In 2019, the Australian Energy Market Operator (AEMO) identified serious risks to the power system in Western Australia, in particular, the South West Interconnected System (SWIS). It has been forecasted that, if action was not taken, the continued uptake of rooftop solar PV could lead to widespread blackouts as early as in 2022 [12].

The current main drivers of the system security risk in Western Australia have been identified in an SWIS update report by AEMO. This includes:

- Stronger than expected growth in Distributed PV (DPV)
- Greater load swings with higher levels of DPV operation
- Changing frequency management requirements with higher load volatility
- Lowered levels of minimum system load and operational demand

9 According to the Australian Energy Market Operator, RTS is defined as "behind-the-meter systems, installed by households and businesses, up to 100 kW Capacity"

- Non-synchronous renewable generation exceeding synchronous generation
- Lowered levels of system inertia and fewer synchronous generators online to sustain power system security and reliability
- Increased frequency of negative prices in the energy balancing market

In South Australia, installed PV capacity is growing rapidly with more than 200 MW being added annually as of 2020. If this growth continues, operational demand (actual demand minus distributed generation, which is met by traditional dispatchable generating units) could reach zero by late 2022. This forecast is based on the minimum operational demand witnessed in the financial year 2019-2020, which occurred during mid-day on November 2019 and assumes high Distributed Energy Resources additions (DERs) as well as extreme conditions, where mild temperatures, clear skies and low economic activity coincide [13].

One of the most significant immediate challenges in both South and Western Australia is managing power system security during times when the operational demand is very low. In these situations, traditional dispatchable power stations cannot operate. These power stations provide essential network services such as maintaining power system strength, inertia, frequency and voltage. Although DERs can provide some of those services, their current performance standards (In particular disturbance ride through capabilities) and compliance with these standards[10] must be improved to ensure secure power system operation with high penetration of DER. As these improvements are underway, immediate measures must be taken to address operational challenges. This includes enabling remote control capabilities to all newly installed grid connected PV systems.

According to the AEMO SWIS update report, enabling the capability to manage distribution-connected PV systems (i.e. for output reduction and/or curtailment) based on instructions from AEMO to a third party[11] is a priority on the list of actions recommended to mitigate system security risks and should be done as soon as practically possible.

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10 According to [13],evidence from DER behavior during power system disturbances in South Australia shows that 30-40% of PV system inverters have not behaved according to existing standards.

11 Known as agents, these are typically inverter manufacturers, smart meter manufacturers or companies that specialize in developing smart home and DER management technologies

Approach in South Australia

Inverter technical standards

According to South Australia Power Networks (SAPN), PV Installations (also known as Inverter Energy Systems) connected to the grid must have inverters compliant with the technical standard AS/NZS 4777. Inverters compliant with the AS/NZS 4777.2:2015 standard must have various grid protection capabilities such as [14]:

- Under/Over frequency protection
- Under/Over voltage protection
- Power Quality Response modes
- Volt Watt Response Mode
- Volt-VAr Response Mode
- Voltage balance modes

In addition, Inverters must facilitate Demand Response Management (DRM) capabilities which are defined as automated alterations of an electrical product's normal mode of operation in response to a signal from a remote agent. The minimum requirement for all grid connected inverters is to operate an automatic disconnection device in response to a DRM signal within a maximum time of 2 seconds (DRM 0, as shown in Table 6). Additional DRM modes may be present in inverters as indicated in Table 6 (DRM 0, 5, 6 and 7 apply to PV inverters).

Table 6. Demand Response Modes (DRM); bolded modes apply to PV

Mode	Requirement
DRM 0	Operate the disconnection device
DRM 1	Do not consume power
DRM 2	Do not consume more than 50% of rated power
DRM 3	Do not consume more than 75% of rated power and source reactive power is capable
DRM 4	Increase power consumption
DRM 5	Do not generate power
DRM 6	Do not generate more than 50% of rated power
DRM 7	Do not generate more than 75% of rated power and sink reactive power if capable
DRM 8	Increase power generation

A Demand Response Enabling Device (DRED) is used to provide an interface between the remote agent and the demand controller built into the inverter. The DRED must be connected to the DRM port of the inverter. In case a DRM port is not available, the DRED is installed according to the manufacturer's specifications. Communication with the DRED can be configured based on the remote agent's preference. Common communication methods include Ripple control, Mesh radio or over the internet[12] [15].

For PV non-scheduled generation (PVNSG)[13] systems with installed capacity between 200 kW and 1 MW, with maximum export less than 200 kW, A Network Monitoring Unit (NMU) needs to be installed to provide SAPN with interval data on the electricity generated by the system. This may be done by installing a remote read interval meter which provides the data to SAPN. As the maximum export is less than 200 kW, real time monitoring and control is not required; therefore, data can be provided on a weekly or more frequent basis [16].

Regulatory changes for smarter homes

In 2020 regulatory changes by the South Australian (SA) government for Rooftop Solar (RTS) resulted in the addition of new technical standards to address system security risks. These standards include [17]:

A. Remote disconnection and reconnection requirements

All grid connected PV systems installed after 28 September 2020 must be capable of being remotely disconnected and reconnected by an agent registered with the technical regulator[14]. The role of the relevant agent is to remotely disconnect/reconnect the systems appointed, when legally directed to do so, either by SAPN or AEMO [18].

Some of the main requirements for relevant agents include:

- Utilizing a technology capable of disconnecting and reconnecting generation systems without requiring the agent to physically visit the site of the system
- Disconnect/reconnect all systems, individual systems, multiple systems (by number or location) or a certain level of PV capacity under their control
- Undertake the disconnect/reconnect operation within 15 minutes of being directed to do so and inform the directing party once the operation has been concluded

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12 Ripple control (different from Radio Ripple Control) involves imposing high frequency signals onto the standard 50Hz distribution network. It is commonly used to control various loads such as public lighting and electrical water heaters.
Mesh radio refers to a wireless network formed by a number of nodes that consist of stationary mesh routers. Mesh routers allow clients to connect to the network and forward messages.

13 According to AEMO, PVNSG systems are defined as PV systems with installed capacity between 100 kWp and 30 MWp.

14 Prior to this requirement, PV systems were required to have DRM 0 capability, which would facilitate remote disconnection. However, PV system owners were not required to register with a relevant agent.

The SA government has provided functional descriptions for a range of deemed methods that would allow the relevant agent to operate disconnection devices or limit the energy exported by the inverter to zero through remote signals. These methods include [19]:

- DRED that can assert a DRM0 or DRM5 signal
- Direct communication channel to the inverter
- Electricity (smart) meter
- Network Protection Unit (NPU)
- SCADA system

This, however, is not a comprehensive listing of the technologies that may be used to remotely disconnect/reconnect PV systems from the grid, and it is up to the relevant agent to nominate a suitable technology. To be technology neutral, the SA government has imposed outcome-based requirements for the technology that will be used by the agent.

A list of relevant agents is available online and is updated regularly by the SA government [20]. This list contains an overview of the technology used by each agent. One of the solutions commonly used is to utilize the inverter's internet connection capability to control the inverter export limits or reduce generation via an Application Programming Interface (API)[15].

The technology-neutral approach for remotely disconnecting/reconnecting PV systems has been criticized by some of the stakeholders. According to the feedback received from the consultation on the proposed requirements, a technology neutral approach to communicate with the relevant agents might generate competing standards, negatively impacting the effectiveness of the system. A shared opinion among stakeholders is that the SA Government should support the implementation of the international standard IEEE 2030.5 (See section 3.13). Across the industry, this standard is seen as the end goal for Distributed Energy Resources remote control [21].

B. Export limit requirements

As of 2019, grid connected RTS systems have fixed export limits of 5 kW per phase. As RTS capacity continues to increase, this export limit will likely need to be further reduced. However, for most of the year, the SA power system would be able to support exports above the static limit. To deliver maximum value to RTS system owners and enable continued installations, all grid connected RTS systems must be capable of remotely updating and enacting dynamic export limits.

To achieve this, RTS system owners are required to ensure that the inverter installed is capable to receive remote communication. According to the technical regulatory guidelines, the inverter must have internet capability and an on-board communication port that can be used for a physical connection to another device (e.g. Via ethernet, USB and RS-232). If the inverter can communicate wirelessly in a manner similar to an on-board communications port that can be used for a connection to another device this may be used in lieu of a physical communication port.

15 An API refers to a software intermediary that allows applications to communicate with each other.

C. Smart meter requirements

Typically, smart meters are wired in a low-cost manner where the electricity generating system and customer load are aggregated, i.e. at the grid interconnection point. This allows the Metering Coordinator to individually de-energize and re-energize the whole customer site but not the electrical generating system and customer load separately.

This new regulation requires smart meters to be capable of separately measuring and controlling a controllable load and electricity generating system, i.e. installed at the AC output of the inverter(s). The smart meter installation must comply with the following technical regulator guidelines [22].

Whilst the 3 mentioned requirements (remote disconnection/reconnection, export limits, smart meter) seem to contribute to solving the same issues, the SA Government stated that these requirements are complementary of each other. Dynamic export limits provide for network constraints management, smart meter requirements enable controllable generation and load to respond to tariffs and potentially contribute as an emergency backstop solution, and remote disconnection and reconnection requirements act as an emergency backstop [23].

Approach in Western Australia

According to the Western Australian Government, remote disconnection requirements for RTS installations will take effect from February 2022. Similar to South Australia's regulatory changes for smarter homes, a remote agent will be responsible for remotely disconnecting the PV system when legally directed to do so by AEMO. Proposed methods for remotely disconnecting grid connected PV systems include [24]:

- The use of a DRED
- Electrical (smart) meter
- Communication channel to the inverter
- Communication channel to a device that can relay control signals to the inverter

Currently, the 2019 revision of Horizon Power's (a government owned power company in Western Australia) technical requirements for Low Voltage Embedded Generation (LV EG) and Basic micro EG[16] connections, requires communications for remote monitoring and control only for LV EG connections with installed capacity greater than 200 kVA. Systems with installed capacity bellow 200 kVA are not required to have such communication facilities [25].

Horizon Power is obliged to supply the system owner with a preconfigured gateway device and SIM card to monitor and control the output of the PV system's inverter. The PV system owner is responsible for the expenses of the gateway device. This gateway device (a Cybertec 3G Modem preloaded with a 3G SIM card) provides a single point interface for the LV EG control system to Horizon Power's Distributed Energy Resources Management System (DERMS) via Horizon Power's SCADA network. Communications between Horizon power's SCADA network and gateway devices at LV EG systems is done via a private (Telstra) 3G cellular network. Finally, the gateway devices communicate with inverters using Modbus TCP/IP protocol.

According to the 2021 draft revision of the technical requirements for Basic EG and LV EG connections, remote monitoring and control will be required for all PV systems connected to the LV grid with installed capacity up to 1 MVA and must be equipped with Horizon Power's preconfigured gateway devices [26].

Additionally, Horizon Power has already implemented the IEEE 2030.5 standard in its Distributed Energy Resource (DER) pilot project in the town of Onslow. As depicted in Figure 11, the DERMS, which runs an IEEE 2030.5 server, communicates with DERs via a Secure Gateway Device provided by the Australian company SwitchDin [27].

16 LV EG includes PV systems connected to the LV grid with installed capacity between 30 kVA and 1 MVA, while Basic micro EG includes PV systems connected to the LV grid with installed capacity up to 30 kVA

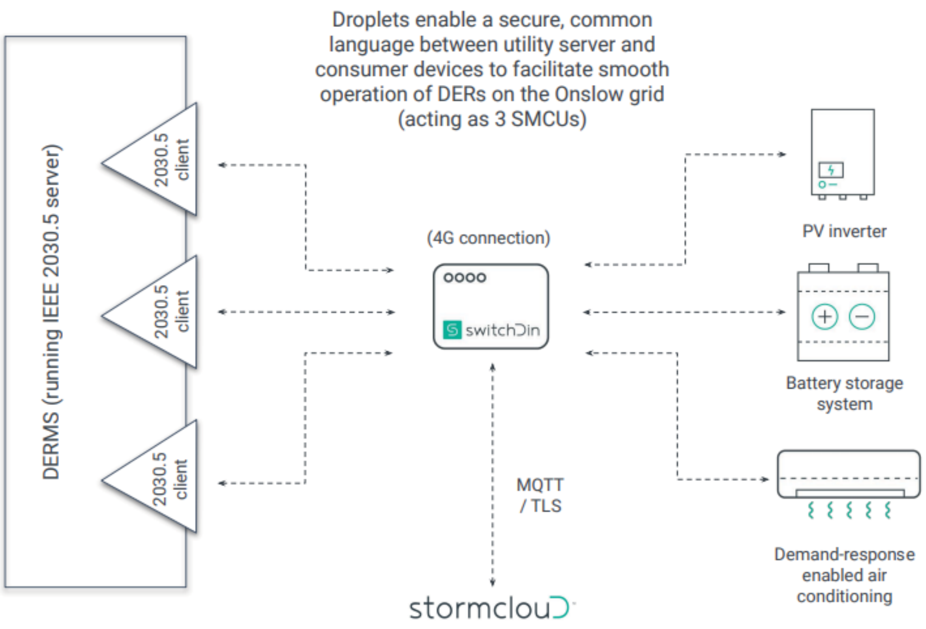

Figure 11. Communication Infrastructure Block Diagram for the pilot project in the town of Onslow [28]

Regulations

Remote disconnection is proposed as an emergency backstop solution and is to be used only in extreme circumstances to avoid the risk of blackouts and extreme 'low load' events. To address low load events, PV system owners could have their system completely turned off and be supplied with electricity directly from the grid. However, it is expected that these circumstances will occur infrequently and will require PV systems to be disconnected for very short periods of time. It is anticipated that this measure will have minor impact on PV system owners, therefore, no compensation schemes are in place in the event of the PV system being requested to disconnect.

3.1.3. USA

The national requirements related to remote monitoring and control in the USA are based on the guidelines in IEEE 1547-2018 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (referred to as IEEE 1547-2018 henceforth). The standard is voluntary and the state regulators and governing bodies need to adopt them to enforce it. Most of the requirements listed in the standard have already been mandated in California (rule 21) and Hawaii (Rule 14H) [29]. Furthermore, Maryland updated its rules in 2020 to approve only inverters certified to IEEE 1547-2018 for grid connection, starting 1 January 2022.

Overview of requirements of IEEE 1547-2018

A Distributed Energy Resource (DER) is defined in IEEE 1547 as 'a source of electric power that is not directly connected to the bulk power system'. The definition includes distributed generators and storage technologies, while exempting standby generators and controllable loads for demand response. The standard marks a significant evolution of grid support functions required from DERs over the previous standard (IEEE 1547a-2014) as shown in Figure 12. The standard applies regardless of the type and size of DER. It however gives precedence to other standards for synchronous generators greater than 10 MVA [30].

The standard splits DERs into two categories; A and B[17], which differ regarding the voltage regulation capabilities required. All DERs (categories A and B) must be capable of three voltage regulation control modes: (1) constant power factor mode, (2) voltage-reactive power mode (i.e. volt-volt ampere reactive), and (3) constant reactive power mode. For Category B DERs, two additional voltage regulation capabilities are required: (1) active power-reactive power mode (i.e., watt-volt ampere reactive) and (2) voltage-active power mode (i.e., volt-watt). Further, all DERs are required to have voltage/frequency ride through and frequency response capabilities as per the requirements in the standard.

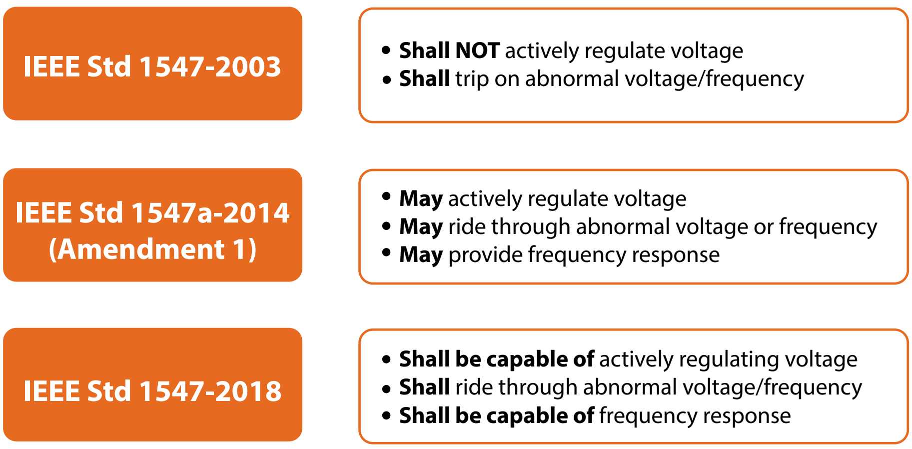

Figure 12. Evolution of grid support functions required from DER in IEEE 1547 [30]

17 Whereas category A is required for all DER systems, category B is attained mostly only by smart (advanced) inverters as it requires more advanced capabilities, which are required in contexts of high DER penetration.

The standard further lists new interoperability requirements, which are the focus of this section. As per these requirements, a DER shall have provisions for an interface capable of communicating (local DER communication interface) to support the information exchange requirements specified in this standard for all applicable functions that are supported in the DER. The standard further requires this interface to support one of the three protocols: IEEE 2030.5, IEEE 1815, or SunSpec Modbus for achieving interoperability. The physical layer is specified as Ethernet for the three protocols (RS-485 mentioned also for Modbus). It divides the information to be exchanged in four categories [31]:

- nameplate data: includes characteristics of the installed DERs such as power and reactive power rating, voltage ratings, normal and abnormal performance categories and unit identification.

- configuration information: each element in the nameplate information should be configurable, Configuration information is intended to describe DER's present capability and ability to perform functions. Each nameplate value has a corresponding configuration value.

- monitoring information: present operating conditions of the DER

- management information: information for updating the functional and mode settings. Four functions are listed for external control namely disable permit service, limit active power, change functional mode (volt/var, power factor etc.), and change parameters for control and protective functions.

The decision regarding when to use the control capabilities is left to the area power system operator. The certification standard IEEE 1547.1 was revised in 2020 to include test procedures for evaluating the IEEE 1547-2018 interoperability requirements.

California Rule 21

California currently has 40% of the installed solar capacity in the USA. The California Energy Commission has also mandated that new single-family homes and multi-family dwellings up to three stories high must include solar panels from January 1st, 2020. This mandate will further increase solar PV installations in the state. This makes it an important region vis-à-vis regulations related to DER integration [32].

The California Public Utility Commission adopted the CA rule 21 in 2014. The rule brought forth many of the advanced functional capabilities for inverters (also defining the term 'smart inverter') which are now included in IEEE 1547-2018. The rule had the following phases of implementation: Phase 1, comprised of the autonomous functions which inverters interconnected to the distributions system must perform; Phase 2, described the communication protocols between the utility, DER aggregators, DERMS, and DERs themselves; and Phase 3 which listed the advanced DER functions requiring communication and control. Phase 1 is in effect from September 9th, 2017, while Phase 2 and Phase 3 were mandated from June 22nd, 2020.

Communication requirements

The rule breaks down communication scenarios between three use cases: Scenario 1 with direct DER communications, Scenario 2 with Generating Facility Energy Management System (GFEMS) communication and Scenario 3 with an Aggregator . Rule 21 Phase 2 states that the default protocol for communication between the utility DERMS and the end device (based on the three use cases) would be IEEE 2030.5 unless another protocol is mutually agreed upon. The communication between Aggregator/GFEMS and DER is out of scope of the document.

It should be noted here that IEEE 1547, unlike CA rule 21 only applies to the actual smart inverter system and not to any upstream aggregation or GFEMS system or the DERMS system. As previously mentioned, in IEEE 1547 supported protocols are only defined for the local DER communication interface (IEEE 2030.5, IEEE 1815, or SunSpec Modbus). The external communication network characteristics (linking to the utility system) is determined by the area power system operator. In a report published by IEEE [33], it is mentioned that communication between the utility SCADA system and large DER units for direct monitoring and control will most likely use IEEE 1815 (Distributed Network Protocol -DNP3), whereas communication between utility DERMS and DER controllers or aggregators will require gateways that could use for example SunSpec Modbus, DNP3, IEEE 2030.5 and/or IEC 61850.

Monitoring requirements

The implementation details for the standard are provided in SunSpec Common Smart Inverter Profile (CSIP) [34]. The monitored data required as per the CSIP include: active power, reactive power, frequency, voltage per phase (along with data qualifiers such as mean, maximum, minimum). The status information data include: operational state, connection status, alarm status and operational energy storage capacity. These are listed in Table 7.

Table 7. Monitored and status information data as per CA Rule 21

Monitored data	Active Power
	Reactive Power
	Voltage per phase
	Frequency
Status information data	Operational state
	Connection status
	Alarm status
	Operational energy storage capacity(battery)

Control requirements

The autonomous power control modes listed in the document are ramp rate control, voltage-frequency ride through, power factor control and volt-var characteristic. The advanced power control modes required are volt-watt and frequency-watt.

The advanced control functionalities utilizing communication are listed below:

- Disconnect/Reconnect – with this function the utility can de-energize circuit to perform maintenance repairs or to prevent unsafe conditions during emergency
- Limit Maximum Active Power Mode - limit maximum active power output to a specified value in areas of high distribution penetration to limit voltage issues
- Set Active Power Mode – set the active power to a specified value
- Changes in default settings of autonomous modes: The default settings for autonomous

functions such as ramp rate control, voltage-frequency ride through, power factor control and volt-var characteristic should be changeable via communication

- Scheduling Power Values and Modes – Scheduling allows the server to schedule autonomous and advanced power modes for a single DER or a group of DERs at a future point in time for a given duration.

Hawai'i Rule 14H

This standard provides technical guidelines for the interconnection operation of distributed generating facilities with Hawaiian Electric Company. The standard itself states that requirements therein are based on requirements of IEEE 1547, unless otherwise stated. Table 8 shows how requirements for remote monitoring and remote control of DERs were less advanced compared to California Rule 21 and to IEEE 1547 until 2020. It is expected that by April 2022, Hawaii (and California by mid-2022) will adopt IEEE 1547-2018, with new requirements as shown in Table 8 for IEEE 1547 [35].

Regulations

Under Hawaii Rule 14, behind the meter PV systems should only be curtailed in case of grid emergencies. No compensation will be provided for losses incurred during the curtailment period. The utility is required to submit a summary of curtailment events and proof of the need for curtailment on a quarterly basis [36].

Under CA rule 21, the distribution provider may limit the operation or disconnect the PV system at any time with or without notice in emergency conditions. An explanation for the reason of curtailment or disconnection must be provided to the system owner upon request [37].

A comparison of these monitoring and control requirements between IEEE 1547-2018, California Rule 21 and Hawaii Rule 14H was done in by North American Electric Reliability Council (NERC) and is provided in Table 8.

Table 8. Comparison between IEEE 1547 and other DER interconnection standards [29]

Functions	IEEE 1547-2018	CA Rule 21	Hawai'i Rule 14H
Communication interface	Yes, should support IEEE 2030.5/IEEE 1815/Modbus	Yes, default protocol IEEE 2030.5 at end device	Yes
Monitor DER data	Yes	Yes	No
Disconnect/ reconnect	Yes	Yes	Yes
Ramp rate control	Yes	Yes	Yes
Limit active power	Yes	Yes	No
Set Active Power	No	Yes	No
Scheduling Power Values and Modes	No	Yes	No

3.1.4. Italy

In 2012, the Italian Transmission System Operator (TSO) TERNA has adopted a procedure for distributed generation (DG) curtailment in case of emergencies known as the RIGEDI procedure. This procedure is applied to PV and wind generators connected to the MV distribution level and with an installed capacity equal to or greater than 100 kW [38].

The DG systems were classified into various categories, each with a different RIGEDI scheme for active power curtailment. These schemes are described as follows:

- GDPRO: This scheme is implemented for DG systems connected to the grid with non-dedicated lines to which are also loads connected. These systems are disconnected manually by the owner upon request from the DSO.

- GDTEL: This scheme is implemented for DG systems connected to the grid with dedicated lines and feed all net production into the grid. These systems are disconnected with a 60-minute notice by the DSO's remote-control system at the TSO's request.

- GDRM: This scheme was added in 2014 and is also implemented for systems connected with dedicated lines, which feed all net production to the grid. In this scheme, the DG is disconnected by the TSO's defense system via the DSO's remote-control system in real time (with a notice of only a few minutes to the owner). The dedicated line, through which GDTEL and GDRM systems are connected to the grid can be opened using a motorized switch-disconnector remotely by the DSO. The DG systems are linked to the DSO by means of GSM/GPRS modem connected via a communication network. Figure 13 shows the communication architecture between DSOs and PV systems for both the GDTEL and GDRM schemes.

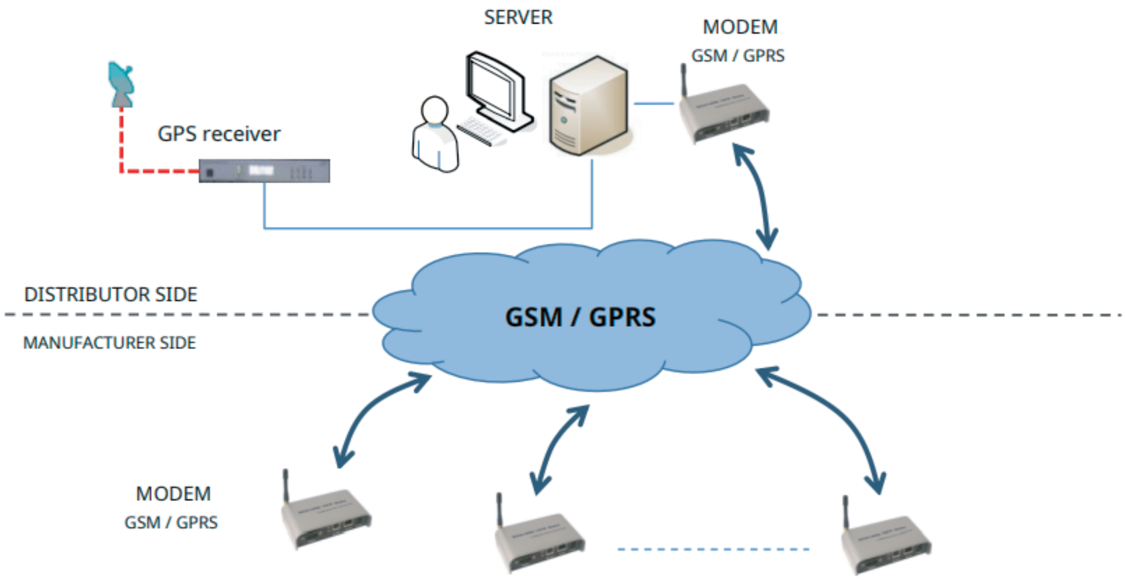

Figure 13. Communication system architecture [39]

The communication system must allow the DSO to perform the following actions:

- Send a disconnection command, as well as the date and time the system will be disconnected/reconnected
- Receive a confirmation signal that the system has been disconnected/reconnected
- Send a reconnection signal, allowing the system to be reconnected to the grid and resume production
- Acquire diagnostic signals, to verify correct functioning of the telecommunication network and remote disconnection system
- Acquire estimates of the power produced by the system.

3.1.5. Thailand

Thailand has been for many years a reference in Southeast Asia for renewable energy development. Due to this status, it has been included in the review. Findings of the review of current requirements, focusing on remote monitoring and remote control of solar PV connected to the distribution level, are presented in this section.

Status of RE penetration and comparison to Viet Nam

Thailand was for many years ahead of its neighboring countries regarding renewable installations in Southeast Asia. However, Viet Nam has recently (and in an extremely short time) surpassed Thailand in terms of installed solar PV capacity.

Figure 14 shows a comparison of Thailand's total solar installed capacity to Viet Nam's. In Thailand, the renewable share is 22% of total installed capacity and solar represents 6% of the total installed capacity. In Viet Nam the renewable installed capacity corresponds to 51% of total installed capacity, and solar is 24% of the total capacity (with more than half being RTS systems) [40].

THAILAND

Capacity in 2020	MW	%
Non-renewable	**41,541**	**78**
Renewable	**11,991**	**22**
Hydro/marine	3,107	6
Solar	2,988	6
Wind	1,507	3
Bioenergy	4,389	8
Geothermal	0	0
Total	**53,532**	**100**

VIETNAM

Capacity in 2020	MW	%
Non-renewable	**33,706**	**49**
Renewable	**35,649**	**51**
Hydro/marine	18,165	26
Solar	16,504	24
Wind	600	1
Bioenergy	380	1
Geothermal	0	0
Total	**69,355**	**100**

Figure 14. Installed capacity in 2020 in Thailand (left) versus Viet Nam (right). Source: IRENA country energy profiles.

Overview of requirements in the distribution level

In Thailand, distribution grids and retail are operated by the Metropolitan Electricity Authority (MEA) in the greater Bangkok area, and the Provincial Electricity Authority (PEA) in the rest of the country. Both distribution and retail companies are state owned. Privately owned generation is classified into IPPs (in this case operator of large power stations >90 MW), Small Power Producers (SPP, >10 MW) and Very Small Power Producers (VSPP, ≤10 MW). Transmission grid and a considerable share of generators are owned and operated by state utility EGAT (Electricity Generation Authority of Thailand), who are also in charge of bulk electricity sales.

At the distribution level, both authorities (PEA and MEA) have their own interconnection codes and requirements for inverter-based generation. The PEA interconnection code is the newest most advanced of the two grid code documents and will be the focus of this review.

In PEA, requirements are stated in the "Provincial Electricity Authority's Regulation on the Power Network System Interconnection Code B.E2559 (2016)" [41]. It can be concluded from the document that a remote-control capability and SCADA connection is only required for RTS systems above 1 MW connected to the medium voltage system and for all RTS systems connected to the high voltage system. Specifications are detailed in the following sections.

Metering System

The power meter needs to follow PEA's standards. Furthermore, if the converter capacity in the connection request is above 250 kW, a power quality meter is required at the interconnection point. The equipment must be such that PEA is capable of observing the measurements in real-time, however, it does not specify how and if PEA is actually monitoring all systems above 250 kW.

Remote Control

Units with inverters above 1 MW connected to 22 kV or 33 kV, and all units connected to 115 kV, must have a Remote Terminal Unit (RTU) or Remote Control Switch (RCS) and also install communication system linking to the SCADA system which is distributed by PEA's Power Dispatch System Operator.

Conclusion

Current practices and requirements for renewable generation in Thailand are mostly well adapted to the current renewable shares in Thailand. Neither remote control nor connection to SCADA is required for inverter-based systems up to 1 MW. For inverter-based systems above 250 kW, a power quality meter is required and the PEA should be able to access the results in real-time, however it is not clear how often monitoring in real-time is actually done for each system. Although Thailand has regional similarities with Viet Nam, it has not experienced the rapid increase in installed rooftop PV systems that Viet Nam has. Consequently, the impact of rooftop PV in Thailand's grid and suitable technical solutions to mitigate such impacts cannot be directly applied to Viet Nam.

3.1.6. Overview of findings

An overview of the key findings regarding remote monitoring and control for the countries reviewed can be found in Table 9.

Table 9. Comparison of countries and status of remote monitoring and remote control of RTS systems.

Characteristic	Germany	Australia	USA	Italy	Thailand
Level of implementation of remote monitoring and control for PV systems up to 1 MW	Implemented (requirements linked to system size).	Implemented (requirements linked to system size).	Implemented in CA and Hawaii.	Partially implemented (limited to units in the MV level).	Partially implemented. (limited to capability of monitoring units >250 kW).
Requirement for remote monitoring in distribution level	Required for PV systems with installed capacity above 100 kW.	SA: Required for PV systems with installed capacity above 200 kW. WA: Required for PV systems with installed capacity above 200 kVA.	IEEE 1547 and CA Rule 21: required for all DERs regardless of type and size. Rule 14H: No requirement.	No requirement for real time monitoring. Estimates are provided to DSOs and TSOs based on irradiation measurements	For inverters above 250 kW, power quality metering must be accessible in real time by the DSO.
Requirement for remote control in distribution level	Required for PV systems with installed capacity above 30 kW[20].	SA: Required for all grid connected PV systems. WA: Required for PV systems with installed capacity above 200 kVA[21].	IEEE 1547 and CA Rule 21: advanced control functionalities for all DERs are required. Rule 14H: only capability to disconnect DER is required.	All PV systems with installed capacity over 100 kW connected to the MV grid via dedicated lines are required to be remotely disconnected	Remote control required for PV systems with inverter capacity above 1 MW and for all HV connected units.

20 From 2021, systems with installed capacity over 25 kW will be required to be remotely disconnected.
21 According to the draft 2021 revision of the Basis and LV EG technical requirements, all PV systems connected to the LV grid regardless of installed capacity will require remote monitoring and control.

Integration to utility SCADA system	PV systems above 100 kW are integrated to the utility SCADA system.	SA: Required for PV systems with installed capacity greater than 1 MW. WA: Required for PV systems with installed capacity above 200 kVA.	DERs integrated into the utility DERMS system.	Not integrated.	Required for PV systems with inverter capacity above 1 MW and for all HV connected units.
Conditions for curtailment of RTS systems	PV systems should be curtailed in emergency situations only. Proof of the need for curtailment must be provided to the PV system owner on request. Affected PV system owners are compensated.	Proposed as a backstop solution to avoid backouts or extreme low load events. No compensation is provided for affected PV system owners.	PV systems can be curtailed in emergency situations only. Proof of the need for curtailment must be provided to the PV system owner on request. No compensation for affected PV system owners.	Not found.	Not found. [42]Indicates that there is no policy for curtailment.

The key findings of the international review include:

- **Remote control capability:** Capability of being remotely disconnected is a minimum requirement in all countries with a high RTS share. Capability to reduce PV system feed-in to certain levels is a common requirement.
- **Remote monitoring capability:** Remote monitoring is a common requirement for PV systems above 200 kW. Germany already requires remote monitoring for PV systems above 100 kW and in the US, California and the states that apply IEEE 1547 require remote monitoring from all DER (regardless of size and type).

- **Integration of RTS to the utilities SCADA** system is not yet common practice. Among the countries with high RTS share, many require larger RTS systems (example RTS systems above 100 kW in Germany and above 200 kVA in Western Australia) to be capable of being connected to the SCADA system of the utility, however it is a decision of the utility to establish or not such communication with individual systems. In the US, states that adopt IEEE 1547 and California require all DERs to be integrated to the utility's distributed energy resource management system (DERMS). Although there are several ongoing DERMS pilot projects, best practices for DERMS have not yet been defined [43].

- In Germany, US and Australia, PV systems should be **curtailed in emergency situations only**. Additionally, for Germany and the US, proof of the need for curtailment must be provided to the PV system owner on request, and in Germany owners of curtailed plants are compensated.…

3.2. Review and comparison of possible solutions/technologies to enable remote monitoring and control

3.2.1. Communication architectures that allow DSO-inverter data exchange

There are three primary ways in which the utility can communicate with the DER depending on the architecture setup, as identified in CA rule 21 [34]. The setup is shown in Figure 15 and Figure 16 and explained below:

- Utilities communicate with individual DERs directly: The utility directly communicates with the DER system either via an interface embedded in the inverter itself (Client 1 shown in Figure 15) or with an external gateway device (Client 2 shown in Figure 15). This gateway device is a communications device for the DER and is connected to the DER via mediums such as RS-485, ZigBee, Wi-fi, etc.

- Utilities communicate with Energy Management System (EMS) which controls different DERs: The communication here is between the utility and the EMS (Client 3 shown in Figure 15), and the EMS has control over the individual DERs. The communication protocol between EMS and DER is not important for the utility and hence is out of scope of CA Rule 21.

- Utilities communicate with an aggregator/virtual power plant owner (as shown in Figure 16): This scenario is applicable if there is an aggregator/virtual power plant owner controlling multiple DERs. The utility communicates with the aggregator who is then responsible for relaying information to and from the DER. The communication protocol between aggregator and DER is not important for the utility and hence is out of scope of CA Rule 21.

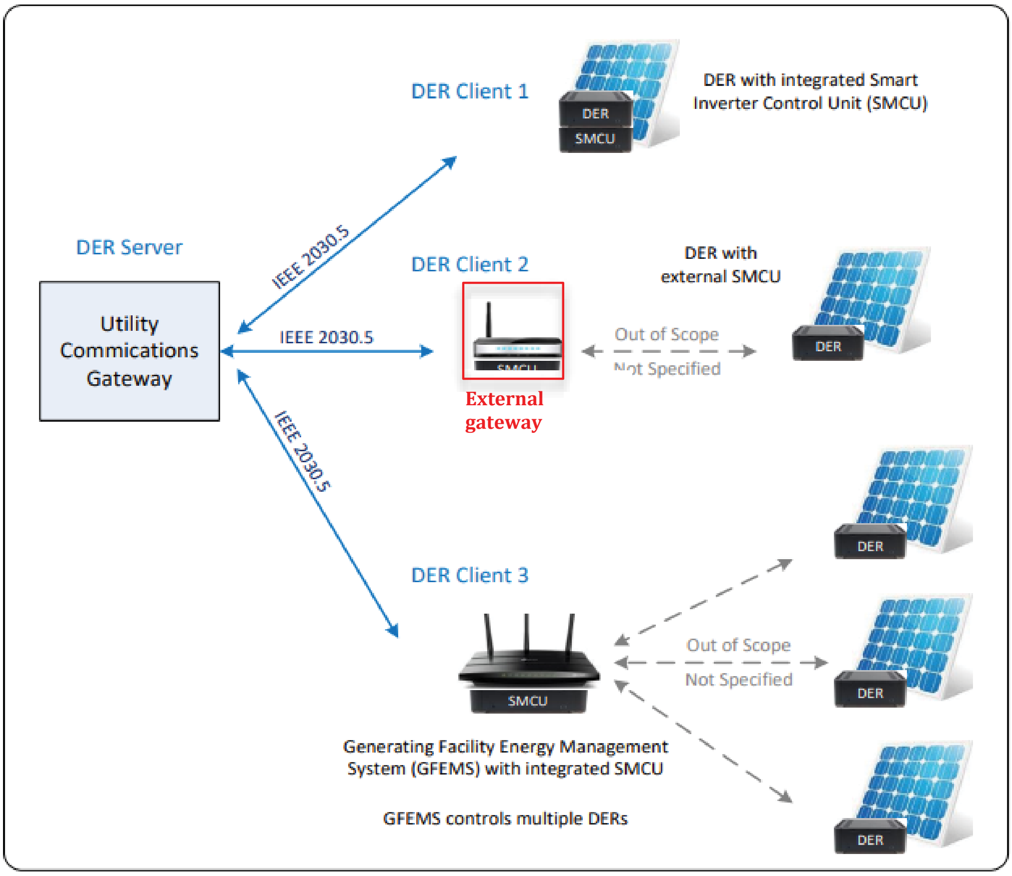

Figure 15. Direct DER communication solutions [34]

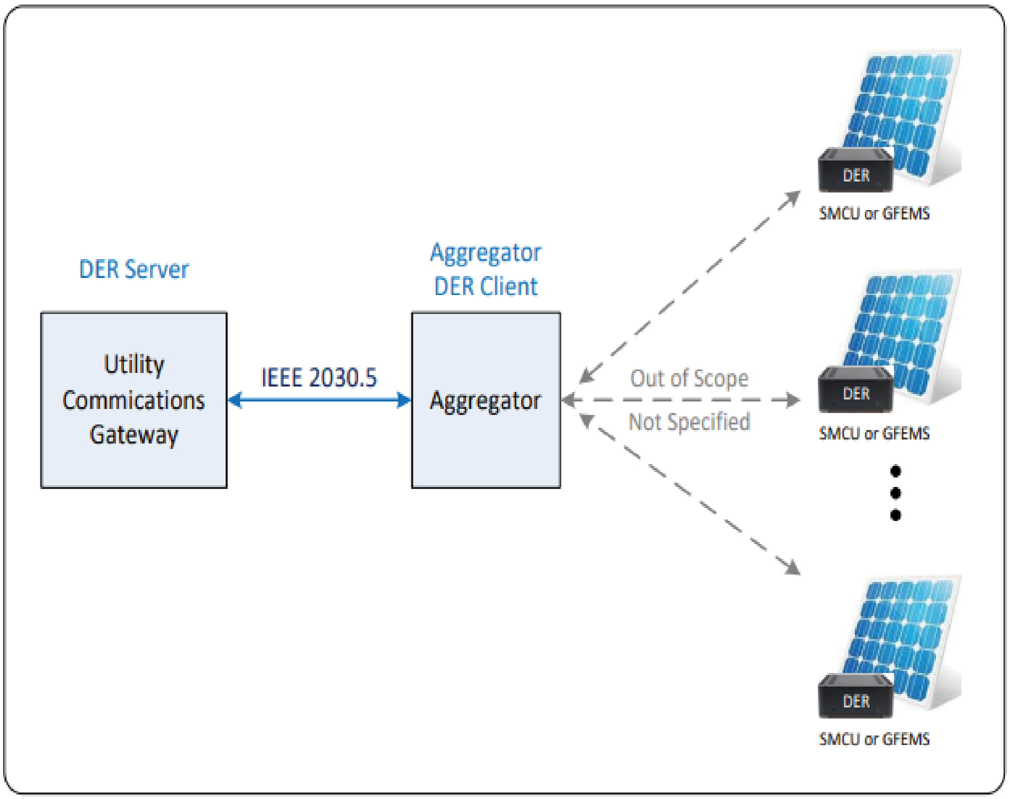

Figure 16. Aggregator mediated communication [34]

3.2.2. Communication technologies

Application layer protocols

It is extremely important to have standardized communication protocols to enable interoperability between the utility and the various DERs, while also ensuring security of information flow. This section describes the various standardized application layer protocols (and information models) in use today for DER devices. These are listed below:

- **IEEE 1815 (also referred to as DNP3) and IEEE 1815.1:** IEEE 1815 is widely used in the US for real-time SCADA control of substations and utility-controlled DER. The communication is defined between two endpoints: master (which is the computer used in the control centre) and the slave (outstation devices, which could be sensors, PV inverter, RTU). Different variables can be assigned different priority levels which allows for giving precedence to high priority messages, thereby helping in network traffic management. The rules are setup in a way to allow communication using limited network bandwidth and unreliable communication systems. The protocol uses a combination of Transport Layer Security (TLS) encryption and authentication procedures for security. The data models for this protocol are from the application note of Distributed Network Protocol (DNP) organization which are based on the structured data models of IEC 61850-7-420 [44]. This allows easy integration of system integrating DNP3 with IEC 61850 network using a gateway. The guidelines for a consistent method to map between DNP3 and IEC 61850 are provided in IEEE 1815.1 standard [45] . The physical layer is most commonly a simple RS-232, RS-485, Ethernet or radio interface.

- **IEEE 2030.5 (also referred to as SEP2):** IEEE 2030.5 is an application layer protocol designed specifically for managing behind-the-meter DER devices in the smart grid space. The devices here could be meters, smart appliances, plug-in electric vehicles, energy management systems, and DERs such as PV systems and energy storage systems. It is communication layer independent – it includes support for Wi-Fi, Ethernet, Bluetooth, Zigbee and Broadband over Power Line Communication (PLC) (device which supports User Data Program and Transmission Control Protocol/Internet Protocol -TCP/IP). It has strong security features, which includes TLS 1.2 encryption, authentication, authorization and accounting requirements. The implementation guide is as per Common Smart Inverter Profile (CSIP) which is also built as per the data models in IEC 61850-7-420. It is one of three communications protocols in new IEEE 1547-2018, and the default communication protocol in CA Rule 21. This protocol supports wide range of physical media such as Bluetooth, Wi-Fi, Ethernet, broadband over PLC etc. [46].

- **IEC 61850:** IEC 61850 is more common in European and Asian countries as a standard for substation SCADA communications. It comprises of information models defined in IEC 61850-7-420 and the protocols defined in IEC 61850-8-1 and IEC 61850-8-2. The information models have been developed specifically for communication with DER assets outside of the substation. It mostly employs TCP/IP and Ethernet link as a communication medium. It has low configuration and installation costs. This standard is gaining recognition as a benchmark for DER communication protocols. However, it does not have a robust certification program for DER applications. The standard itself does not include security but this is covered through the IEC 62351 standard.

- **SunSpec Modbus:** SunSpec Modbus is an open Modbus based communication protocol conforming to the standards of the SunSpec alliance. It specifies parameters and settings for controlling and monitoring DER systems. It can be deployed over both serial and TCP/IP communication interfaces. It is designed to be interoperable with IEEE 2030.5 and IEEE 1815. While SunSpec Modbus did not include any encryption or authentication initially, it now supports TLS 1.2 encryption, same as IEEE 2030.5. It is currently the prevailing technology for native control of DERs. It is focused on inverter control settings and is mostly used for short-distance communication from the inverter to a IEEE 2030.5 or IEEE 1815 gateway [46], [47].

- **OpenADR 2.0 (Open Automated Demand Response):** OpenADR has been widely used as a demand response (DR) standard for managing peak demand, fluctuations and emergencies. It was developed in California but is used in Japan, Korea, the US and Europe for DR communications. It is also an open communication protocol. OpenADR 2.0 is the latest version and it is intended for communication between utility and DER end device. It therefore relies on a gateway device to convert utility requirements to device specific behaviour. It covers information related to specific DER reduction/increase, pricing, availability and shifting strategies, which are typically decided at the utility. OpenADR version 2.0 can be secured through TLS and Public Key Infrastructure (PKI).

Apart from technical aspects, adoption ease, interoperability and international mandates are some other factors which make a protocol attractive. A comparison of different protocols regarding such aspects is shown in Table 10.

Table 10. Comparison of different protocols

Protocol	Transport Layer	Security	Mandates	Interoperability-data models	Other benefits
IEEE 1815	TCP/IP over Ethernet, serial, UDP/IP	TLSv1.2	IEEE 1547	DNP3 application note based on IEC 61850 data models	Used for SCADA. Effective in low band-width, unreliable network
SunSpec Modbus	TCP/IP over Ethernet, serial	Supports TLSv1.2	IEEE 1547	Based on IEC 61850	Focused on inverter control settings
IEC 61850	TCP/IP over Ethernet	Through IEC 62351	IEC	IEC 61850 data models	Used for SCADA, wide vendor community, low costs
IEEE 2030.5	TCP/IP – Wifi, Zigbee, Bluetooth etc.	TLSv1.2	CA rule 21, IEEE 1547	Requirements in CSIP, based on IEC 61850 data models	Specifically for DERs – robust certification program
OpenADR 2.0	IP based communication	TLS/PKI	IEC	Interoperable with other protocols	Used for DR- sending price and availability signals

The choice of the protocol and configuration of the communication network depends mostly on the DER configuration in place, which can be a communication to individual DER, to Generating Facility Energy Management System (GFEMS) or to aggregators (as exemplified in Figure 15 and Figure 16).

For direct communication between the utility and large DER systems, IEEE 1815 (also referred to as DNP3) and IEC 61850 are mostly used.

For short-distance communication (e.g. from the inverter to a DER gateway or DER controller) SunSpec Modbus is used as it focuses on inverter control settings.

Between the utility communication Gateway and DER Aggregator or DER gateway, IEEE 2030.5, DNP3 or IEC 61850 are most commonly used.

IEEE protocols are more common in the US whereas IEC protocols are more common in Europe and Asia.

Communication network structure and technologies

The communication network is divided into three categories classified by geographic area: wide area network (WAN), neighborhood area network (NAN)/field area network (FAN) and the home area network (HAN). A HAN comprises of network of DERs/appliances within a home. The NAN is where metered data from HAN gets concentrated and the WANs are the high bandwidth communication back to the utility Distribution Energy Resource Management System (DERMS). Different communication technologies can be used for different networks depending on coverage distance and data rate for the network under consideration as shown in Figure 17.

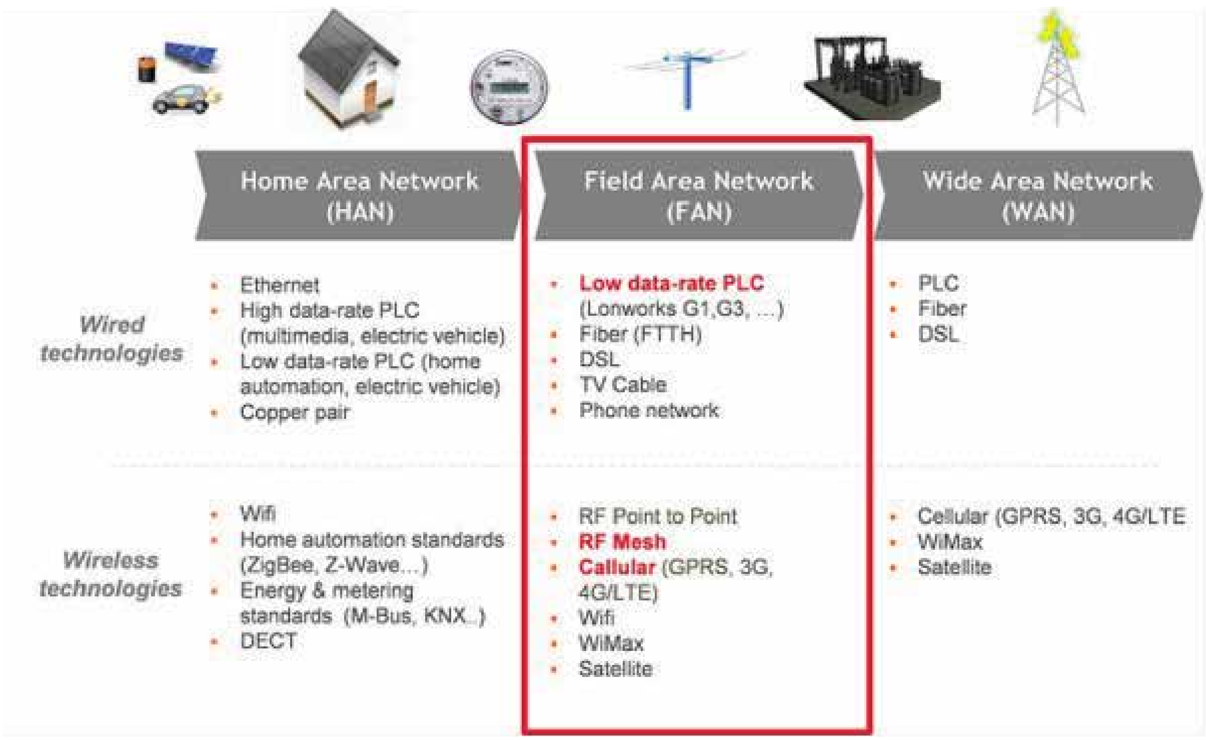

Figure 17. DER control network structure (Source: BearingPoint)

The typical data rate and coverage required for different network types are listed in Table 11.

Table 11. Overview of network types and requirements.

Network Type	Coverage	Data rate requirements	Data rate
WAN	10 – 100 km	High data rate	10 Mbps – 1 Gbps
NAN/FAN	10 m – 10 km	Dependent on node density and topology	100 kbps – 10 Mbps
HAN	1 – 100 m	Generally low-data rate	10 – 100 kbps

The main communication technologies dominating the AMI market are listed and reviewed below:

- **PLC:** Power Line Communication (PLC) uses the power lines that run between the distribution transformer and the customer meters. It operates by modulating in a carrier wave over the existing wiring system. It is a mature technology and is divided into two categories: narrow-band PLC for low data rate communication and broad-band PLC for high data rate applications. The former is predominantly used for AMI applications. The initial cost of PLC is low since it uses already existing infrastructure. It is highly reliable with a range of several kilometers and can easily reach meters which are difficult to access (in basements, high buildings etc.). Its installation easiness is also considered an advantage. The use of PLC is partly dependent on the local grid topology in terms of number of meters per transformer as concentrators for PLC reside inside a transformer (high density of meters therefore reduces the cost). The disadvantages of PLC include lower latency and noise interference from other equipment in the power grid.

- **Radio Frequency Mesh (RF-Mesh):** This technology is based on the unlicensed RF spectrum using a mesh topology. Its independence of electrical grid, good bandwidth and economic competitiveness are some of the major advantages. RF Mesh is a popular solution for AMI in Japan and USA while stricter RF regulation has limited its use in Europe. The technology is well-adapted for urban areas with low obstacles and easy access to meters. Signal interference can be a security issue and lead to temporary data loss, as the communication is on the unlicensed spectrum.

- **Cellular Communication:** This communication option requires tie-up with a telecom operator and includes technologies such as GPRS/3G/4G. It is well-suited for areas where PLC and RF-mesh are not feasible or too expensive such as in rural areas. It is quick to activate, has wide coverage area, low latency and the ability to handle large number of devices. The drawback is the dependence on a telecom operator which can affect service quality. The subscription costs for equipment and network congestion can also be limiting factors for wide-spread usage.

- **Low Power Wide Area Network (LPWAN):** Wireless networks for IoT devices that need small amount of data, low bandwidth and long battery life. These modules can run for years on standard batteries and yet are powerful enough to send data to the cloud from garages, basements, etc. LPWAN subtypes are classified into whether the network operates in a licensed or unlicensed spectrum. Standards such as NB-IOT and LTE-M are on the licensed spectrum while LoRAWAN and Sigfox are on the unlicensed spectrum. Licensed LPWAN run on public cellular networks which supports the GSM and 3GPP standard and therefore involve a cellular operator. Unlicensed LPWANs use the radio spectrum which can be used by anyone. The unlicensed LPWANs therefore require setting up private base stations or using the existing public community networks which have no quality guarantee. Licensed technologies offer lower latency (up to 10s) and higher throughput compared to unlicensed technologies [48]. The LPWA networks are actively considered and developed for next-generation smart meters.

PLC is the preferred choice of communication in Europe while in the US, the AMI infrastructure is largely based on RF Mesh solutions (as shown in Figure 18 and Figure 19). The main reasons are:

- A very strict regulation of RF spectrum in Europe, which limits the access to frequencies used for RF Mesh.
- The European architectural characteristics (meters in basement, building materials, thick walls) are less favorable for wireless uses.
- The American electric grid topology: number of meters per transformer is much lower compared to Europe.

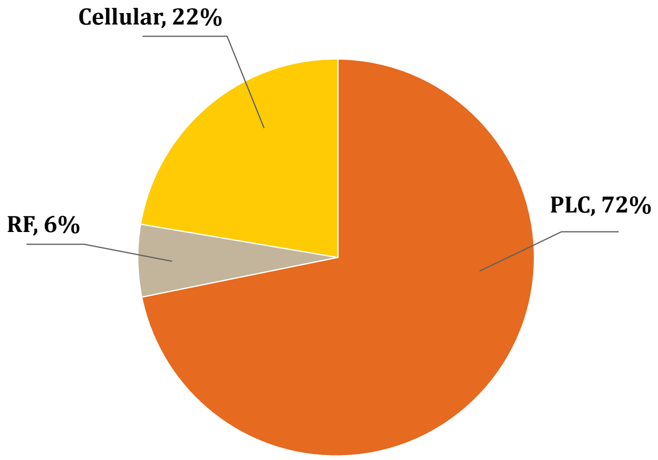

Figure 18. AMI deployments in Europe by technology 2020 (Source: BergInsight)

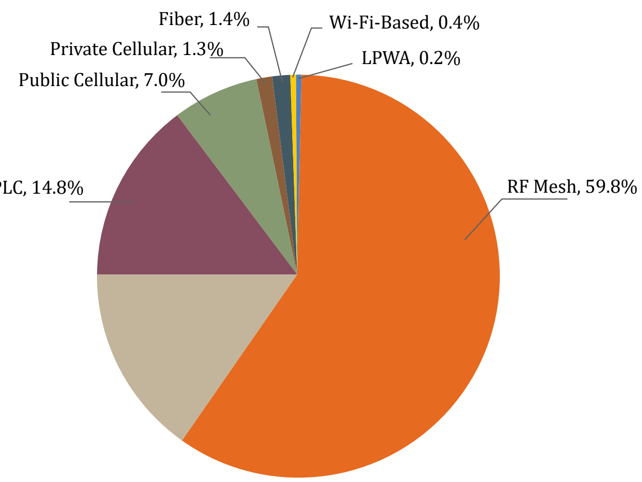

Figure 19. AMI deployments in USA by technology 2020 [49])

A comparison of communication technologies highlighting advantages and disadvantages is presented in Table 12.

Table 12. Comparison of different communication technologies.

	Low Data Rate PLC	**RF Mesh**	**Cellular**	**LPWAN**
Costs	Low installation and maintenance costs	Higher installation cost, low operational costs (equipment locations need to be found).	Low investment, high operational costs	Very low costs (no concentrators needed, low base stations)
Coverage	Complete – can be used where power lines are	High - spectrum not available in certain areas	Widespread – can be difficult in certain topographies	Widespread
Accessibility	High	Low – not in basements, areas with obstacles	Average	High
Range	Few kilometres	Few meters	Few dozen kilometers	100 km for licensed, 10 km for unlicensed
Latency	Low - less than 1 s	Can be high – depends on the number of knots between meter and concentrator	Low – less than 1 s	Low for licensed (up to 10 s), higher for unlicensed
Bandwidth	Low – less than 10 kbps	Average – up to 100 kbps	High – up to 1 Mbps	Low – 20 kbps for licensed, 5 kbps for unlicensed
Service quality-interference	Average	High	Low	Low – higher on unlicensed LPWAN

As exemplified in this section, the choice of the most suitable communication technology needs to be assessed for each location as it depends on the coverage distance and data rate required, as well as on local regulations and restrictions (e.g. regarding the RF spectrum use in each location) and predominant architectural characteristics (e.g. predominant situation of meters in basement, behind building materials or thick walls might make wireless technologies unsuitable).

As shown in Figure 18 and Figure 19, in Europe and the US there is no single solution applied and therefore it is likely that more than one technology is suitable for each location and suitability varies within a country.

4. High level gap analysis of requirements and practices for remote monitoring and control of RTS of Viet Nam compared to international experience

A high-level gap analysis based on key findings of the international and national review is shown in Table 13.

From the gap analysis table it can be seen that Viet Nam has already reached RTS shares of 11% (of total installed generation capacity) which is in a comparable range of shares reached in international countries reviewed (RTS shares of 10.5% to 20.5%), excluding Thailand. As opposed to such reviewed countries with high RTS shares, Viet Nam does not yet have remote monitoring and remote control requirement in place for RTS systems of capacity below 1 MW.

Only recently (October 2021) were basic technical requirements for RTS systems established (such as reactive power capabilities and control modes, fault ride through behavior, etc), however these are limited for systems of installed capacity of above 500 kWp and do not include any remote control and remote monitoring requirements.

Furthermore, under which exact conditions is curtailment of RTS systems allowed and practiced in Viet Nam was not clear from the desktop research and is further reviewed/investigated in the field missions (Chapter 3.). International good practices indicate that curtailment of RTS systems should be limited to emergency situations and justifiable to the PV system owners.

As there is currently no monitoring and control requirements for RTS systems in Viet Nam, the choice of the communication architectures and technologies for this purpose remains open and characteristics of the Vietnamese system are further investigated in field missions, in order to identify one or more suitable solutions.

International practices reviewed will serve as reference for good practices and lessons learnt. Some technologies are already in use by utilities in Viet Nam for different purposes. Stakeholders' experience with such are also be investigated in the field missions and accounted for when recommending a suitable solution for Viet Nam in Chapter 4. (this includes for example the use of GPRS/3G, PLC and RF in the existing AMR solution).

Table 13. High level gap analysis of international practices and national practices.

Characteristic	Germany	Australia	USA	Italy	Thailand	Viet Nam
Share of rooftop solar / total generation installed capacity	20.5% of total generation installed capacity (by the end of 2019)	20.5% of total generation installed capacity (by the end of 2020)	11% in California (of total generation capacity of 80 GW)	10.5% of total generation capacity (by the end of 2019)	1% of total generation capacity (by the end of 2018)	11% of total generation installed capacity (by the end of 2020).
Regulation/ standard that addresses RTS requirements (including remote M&C – if applied)	German Renewable Energy Sources Act (EEG)	AS/NZS 4777	CA Rule 21 HECO Rule 14 IEEE 1547-2018 (voluntary).	RIGEDI procedure	PEA and MEA interconnection codes.	Guidance on technical requirements for RTS inverters (4304/DDQG-PT). Applied for PV systems >500 kW
Level of implementation of remote M&C for PV systems up to 1 MW	Implemented (requirements linked to PV system size).	Implemented (requirements linked to PV system size).	Implemented in CA and Hawaii.	Partially implemented (limited to units in the MV level that feed-in all production).	Limited to monitoring power quality for units >250 kW.	None
Requirement for remote monitoring RTS in distribution level	Required for PV systems with installed capacity above 100 kW.	SA: Required for PV systems with installed capacity above 200 kW. WA: Required for PV systems with installed capacity above 200 kVA.	IEEE 1547 and CA Rule 21: required for all DERs regardless of type and size. Rule 14H: No requirement.	No requirement for real time monitoring.	For inverters above 250 kW, power quality metering must be accessible in real time by the DSO.	None

Characteristic	Germany	Australia	USA	Italy	Thailand	Viet Nam
Requirement for remote control of RTS in distribution level	Required for PV systems with installed capacity above 30 kW (25 kW from 2021 onwards).	SA: Required for all grid connected PV systems. WA: Required for PV systems with installed capacity above 200 kVA[22].	IEEE 1547 and CA Rule 21 required advanced control functionalities for all DERs. Rule 14H: only capability to disconnect DER is required.	All PV systems with installed capacity over 100 kW connected to the MV grid via dedicated lines are required to be remotely disconnected	Remote control required for PV systems with inverter capacity above 1 MW and for all HV connected units.	None
Integration to utility SCADA system	PV systems above 100 kW are integrated to the utility SCADA system	SA: Required for PV systems with installed capacity greater than 1 MW. WA: Required for PV systems with installed capacity above 200 kVA.	DERs integrated into the utility DERMS system.	Not integrated.	Required for PV systems with inverter capacity above 1 MW and for all HV connected units.	None
Predominant architecture used for DSO-inverter data exchange (100 kW - 1 MW units)	Communication Directly to and from DER	WA: DER directly (Gateway/SIM Card is provided); SA: via Agent.	Communication options: directly to DER (to inverter or gateway), to an EMS, or via an aggregator.	None	None	None

22 According to the draft 2021 revision of the Basis and LV EG technical requirements, all PV systems connected to the LV grid regardless of installed capacity will require remote monitoring and control.

Protocols used for remote M&C of RTS (100 kW – 1 MW units)	SML, IEC 60870-5-104	SA: Wide range (technology neutral) WA: IEEE 2030.5	DNP3, SunSpec Modbus, IEEE 2030.5	Internet Protocol between TSO and DSO	None	None. IEC 60870-5-104/101 is used in DSO's SCADA system
Conditions for curtailment of RTS systems	PV systems should be curtailed in emergency situations only. Proof of the need for curtailment must be provided to the PV system owner on request. Affected PV system owners are compensated.	Proposed as a backstop solution to avoid backouts or extreme low load events. No compensation is provided for affected PV system owners.	CA: In the event of an emergency, or to correct unsafe operating conditions. HA: In the event of an emergency. CA/HA: Written justification of curtailment to be provided.	PV systems can be curtailed in emergency situations only. Proof of the need for curtailment must be provided to the PV system owner on request. No compensation is provided for affected PV system owners.	Not found	Only curtailment in case of emergencies is mentioned in PPAs contracts. NLDC sends one week ahead the shares of curtailment to each regional power corporation. This is split into the DSOs, which then call the RTS owners and discuss the request to curtail.

Chapter 02

Key findings from field data collection and introduction of DERMS as a proposed solution

Chapter 2: Key findings from field data collection and introduction of DERMS as a proposed solution

1. Findings from field data collection and analysis

1.1. Objectives

Data was collected through meetings and field trips and evaluated to complement the initial gap analysis for Viet Nam's context, in order to propose a solution. The key points of this activity included:

- Collecting data on the current situation and the views or opinions of different stakeholders.
- Providing suitable solutions based on remote monitoring and control of RTS system in the context of Viet Nam today, to be discussed at a broad consultation workshop with stakeholders.

1.2. Stakeholders and Timeline of Meetings

The stakeholders selected for the interview are those currently performing power system dispatching or grid operation management connecting to rooftop solar power systems. The project also surveyed a number of investors in rooftop solar power projects in Binh Thuan, Quang Nam, and Dak Lak provinces. The list of stakeholders and interview times include:

- National Load Dispatch Center (A0), December 29, 2021 (online meeting)
- Southern Regional Load System Dispatch Center (A2), December 24, 2021 (live meeting)
- Ho Chi Minh City Power Corporation (EVNHCMC), December 24, 2021 (online meeting)
- Southern Electricity Corporation (EVNSPC), December 27, 2021 (online meeting)
- Binh Thuan Power Company and RTS investor, December 28, 2021 (live meeting)
- Quang Nam Power Company and RTS investor, period January 04-05, 2022 (live meeting)
- Dak Lak Power Company and RTS investor, January 06, 2022 (live meeting)

Due to the complicated situation of the Covid-19 pandemic, and some localities restricting movement and limiting contact, some meetings were held online. Most of the meetings (except for those in Binh Thuan, Quang Nam, and Dak Lak provinces) were attended by GIZ.

The interviews included questions relating to the investment process, technical inspection and installation of 2-way meters, solutions and data transmission technology of RTS systems, forecasting and operation management, solutions and technology for monitoring and controlling RTS systems.

1.3. Summary of data collected and recommendations

There are 5 topics which summarize data collected and comments from stakeholders A0, A2, EVN HCMC, EVN SPC, Binh Thuan PC, Dak Lak PC, Quang Nam PC, and investors.

Topic 1 is "Influences of RTS systems on the power system operation and challenges to implement a remote monitoring and control solution for RTS". The biggest issue is the number of RTS systems which is very large, and EVN does not have enough tools to collect data from these systems. This also results in the difficulties in operating the power system which can lead to overload on 110 kV and 220 kV grids, unexpected effect on the voltage of grid, and increase in power losses.

Topic 2 is "Existing SCADA, M&C of RTS, Technology". The data collected from stakeholders show that M&C system implementation is not required as of now, only MV grid requires SCADA implementation, main communication technology is GPRS/4G.

Topic 3 is "Solar Forecasting". Currently, only A0 uses forecasting software, the remaining stakeholders forecast based on experience. A0 sends forecasting data to A2, and others Ax. A0 is transferring forecasting tools to A2 and Ax.

Topic 4 is "Curtailment". A0 analyzes the power system and calculates curtailment (week, day, hour). Then A0 sends the curtailment plan to Ax, Bx.

Finally, **topic 5** is "Additional Comments". These are comments from stakeholders including implementing M&C to collect data, which is subsequently used in operating, forecasting, and controlling RTS system. Several stakeholders have deployed the trail version of M&C.

Detailed answers from stakeholders can be seen on the tables below.

Topic 1:

Stakeholders	Influences of RTS systems on the power system operation and challenges to implement a remote monitoring and control solution for RTS
A0	- Overload on 110 kV and 220 kV grid. - Effect on the voltage of grid - Increase in power losses of grid - Load shedding F81 device cut many times - RTS set parameters in fault mode is not correct, lead to widespread fault
A2	- Have no overload, over-voltage on 22 kV and 110 kV lines of A2 until now. - The PC has installed F90 devices to control the voltage of the MV 22 kV side of the 110 kV/220 kV substation.
EVNHCMC	- The quantity and capacity of RTS in HCMC are not adequate so EVN HCMC can't give the answer about overload, overvoltage, under-voltage when RTS system running. - There are no guidelines and standards for M&C of inverters.
EVNSPC	- The customers/investors agree with the allocated curtailment but don't fully comply with the required capacity and time. - The remote meter data collection system has a delay time of roughly 30-60 minutes. - There are no remote switchgear control devices. - PCs cannot collect data at the connection point of the inverter with meter and modem. - PCs don't have enough staff to both monitor at the office and cut off the power at site. - There are no rigid regulations on the legal framework nor sanctions when RTS's customers/investors don't follow the dispatching command. It is not mandatory to install a remote M&C system. - The AMR systems of RTS systems after the public substation have not yet met the data collection requirements. - The current expertise and lack of tools hinder us from forecasting the capacity of RTS systems/projects.

Binh Thuan PC (BT PC)	- There are 2,906 RTS systems connected to the grid with a total capacity of 330.3 MWp. There are 2,485 solar PV systems connected to the LV grid and 421 systems connected to the MV grid. - The total installed capacities of 111 RTS systems between 100 kW to 500 kW is 23.96 MWp. And of 258 RTS systems above 500 kW is 268.11 MWp. - The EVNSPC provides 2-way electronic meters for the PCs to install in accordance with regulations in EVN. The meter does not support remote control. - About the meter, BT PC complies with regulations of EVN, EVNSPC. Therefore, if EVN and EVNSPC require the installation of smart meters for RTS systems, BT PC will comply with these regulations. - Technological difficulties: PLC has been deployed from 2011 to 2018, and it still does not have a 2-way reading feature. New DCUs have a 2-way reading feature but they cannot collect real-time data about the power of load. The sample time is 30 minutes. - BT PC has no tool to monitor the real-time capacity generated from RTS systems, so there are difficulties in power supply management as well as reports related to the mobilization of RTS system of the EVNSPC. Currently, the remote recording program of EVNSPC is only capable of monitoring the solar PV capacity of date D-1. - There is no database on meteorology (temperature, radiation, ...) from specialized agencies, so the forecasting of capacity generated from solar PV source currently faces many limitations.
Đak Lak PC	There are 5,351 RTS systems connected to the power grid. 4,775 systems are connected to the LV grid and the remain are connected to the MV grid. The total installed capacity between 100 kW and 500 kW is 61.8 MWp and of those above 500 kW is 429.05 MWp.
Quang Nam PC	There are 1,411 RTS systems connected to the grid managed by Quang Nam PC. 1,216 systems are connected to the low voltage grid, and the remaining 195 are connected to the MV grid. - The total installed capacity of the RTS systems between 100 kW and 500 kW is 18,320.69 kWp (87 systems) and the RTS systems above 500 kW is 12,621.655 kWp (132 systems).
Investors (BT)	N/A
Investors (QN)	N/A

Topic 2:

Stakeholders	Existing SCADA, M&C of RTS, Technology
A0	No RTS systems connect to SCADA.
A2	- Do not monitor and control RTS because the RTS is connected to the LV and MV grid. - No RTS systems connect to SCADA. - The Solar Farm must connect to SCADA. - The A2 has no real-time data of RTS now, so it is very hard to operate the power system.
EVNHCMC	- No mention on "M&C connection to SCADA" on Connection Agreement and PPA. - EVNHCMC is installing e-meters with remote data collection features and is testing the AMI systems (roadmap complies with the plan of EVN from 2021 to 2025). - There are no policies or requests from EVN and MOIT for M&C of RTS.
EVNSPC	According to the connection agreement: - LBS and Recloser must be connected to SCADA - EVNSPC and PC installed remote meter for RTS systems that connect to MV grid. - The EVNSPC uses the GPRS/4G modem to collect data of all the RTS systems connected to the MV grid. - The cycle of data collection is every 30 minutes.
Binh Thuan PC	- There is a request "Equipping a data collection and transmission system to connect the SCADA system of the Solar PV system and connect the SCADA to the SCADA University Center to share the control center" in the connection agreement with the customer. - The RTS systems connected to MV grid (use separate substation) use AMR system and GPRS/4G telemetry modem. - The RTS systems connected to LV grid (use public substation) use AMR system and DCU PLC concentrator. - BT PC has 421 RTS systems connected to the MV grid. All these systems installed telemetry and have not yet connected to SCADA of Control Center of BT PC. - Data collected from the telemetry system are U, I, P, Q, PF on day D-1.

Đak Lak PC	- There are 84 solar PV systems connected to SCADA (REC/LBS) on the MV grid. The collected data are U, I, P, Q, PF, state, and control. - Dak Lak PC has a monitoring system for RTS system. They don't control RTS system. - Electronic meter and remote collection system for monitoring comply with EVNCPC's regulations.
Quang Nam PC	- Quang Nam PC is installing electronic meters, there are no requirements for installing smart meters yet. Quang Nam PC will install 100% of electronic meters using 3G/4G, and RF data transmission technology via DCU centralized data collector in 2022. - There aren't solar PV systems connected to the SCADA/DMS system of the Quang Nam PC. - There are 7 of 195 Solar PV systems are connected to the Control Center. These systems are connected to a new system, not the existing SCADA system. Quang Nam PC has an operational database of 7 systems in the last 6 months (U, I, P, Q, PF).
Investors (BT)	No
Investors (QN)	- There are 4 systems (total capacity of 2.5 MW) which have been connected to the GCC/Quang Nam power company for monitoring and controlling.

Topic 3:

Stakeholders	Solar Forecasting
A0	- A0 has 4 forecasting sources in 2022 (2 from an international supplier, 1 from power plants, 1 from the "Self-forecasting" system of A0) - A0 will send a forecasting tool to Ax and PCs (Bx)
A2	- A2 forecasts the capacity of RTS based on their experience and gets the power data of RTS from EVNSPC and EVNHCMC. - The A2 uses the pilot Forecast software made by A0.
EVNHCMC	They have 2 approaches to forecast the capacity of the solar PV systems: - Expert system (based on experience) - Use tools provided by A0.
EVNSPC	- The A0 is transferring the predictive model (D, D+1, D+2); M, Y to SPC. - According to EVN's plan for 2020, EVN has 2 sources to forecast the capacity of the RTS systems. EVN will send the best forecasting models for Power Corporations/ PCs/ Load Dispatch Centers. - The EVNSPC is using Apmeter software to collect data. These data cannot be disclosed now but SPC is willing to share if EVN allows to do so.

Binh Thuan PC (BT PC)	- BT PC has a plan to mobilize RTS power according to the allocation of EVNSPC. - Build a chart of capacity generated from RTS systems in Binh Thuan in which data points are collected every 30 minutes starting from 7:30 a.m. to 5:00 p.m. Based on the power chart and the mobilized power plan of EVNSPC, BT PC determines the level of RTS power that must be cut down in a month. BT PC sends the cutting and closing time to the customer. Task: - Build charts for all districts: + Each district takes 2 typical customers in 2 different areas. + Choose a bright sunny day (registration capacity chart), without any cuts to get the daily power chart. + From 2 charts of 2 typical customers, we will build 1 typical chart for the entire district. For each district, we have a PowerPoint (30 minutes) detailing the maximum power of 2 typical graphs at the same time. Purpose: To ensure that the graph of a district is a collection of the best radiation points to ensure the safety of the option to mobilize the transmit power. - Build a typical daily capacity chart for the whole province: + Based on the chart of the districts and towns built above, the chart for the whole province will be rebuilt with the principle of averaging the power chart of districts and towns (except Phu Quy).
Dak Lak PC	Dak Lak PC uses the forecasting tool of A0. Input variables are weather data and past data.
Quang Nam PC	Quang Nam PC forecasts solar energy based on experience.
Investors (BT)	Investors have forecast capacity of the solar PV system (reference only). Based on the forecast of the software provided by the inverter manufacturer and based on the experience about the weather in the past days.
Investors (QN)	*(The same as the reply of investors at Binh Thuan)*

Topic 4:

Stakeholders	Curtailment
A0	A0 analyzes the power system and calculates curtailment of the next day/ once a week, after that it sends the curtailment plan to Ax, Bx
A2	The PCs perform the mobilization and curtailment power of RTS according to the calculation and allocation of A0.
EVNHCMC	We curtail the power of RTS which connect to the MV grid only and based on the curtailment plan of A2.
EVNSPC	5 steps of curtailment process 1. The A0 calculates and sends curtailment capacity to the EVNSPC. 2. The EVNSPC allocates curtailment capacity to PCs 3. The PC (Dispatch Department) calculates and operates the power grid, then selects medium voltage feeders dispatched to optimize operation. After that PCs are allocated to PC local. 4. The Business Department of local PC (local BD) will: - Select RTS systems/projects of feeders curtailed/mobilized capacity. The criteria of selection are fairness, transparency, meeting the allocated capacity prior to the agreed customers, RTS has a remote-control system, or RTS has remote M&C devices ...to ensure that curtailment is minimized. - Inform customers of the curtailment plan the next day, next week so that customers curtail themselves. - Make a plan for forced curtailment if the customer/investor does not comply with the order of moderation. 5. Supervisor and implementing: - If the customer agrees with the allocated plan, PC monitors via a remote data collection system. - If the customer disagrees with the allocated plan, PC makes a plan to cut off FCO at the connection point.

Binh Thuan PC	Based on the plan to allocate the maximized mobilized capacity of Solar rooftop resources of the EVNSPC. Binh Thuan PC builds a plan to mobilize solar rooftop power for each project. The staff of BT PC announces to investors the plan of the mobilization. The RTS systems do not have to connect SCADA to the Control center of Binh Thuan PC, so the mobilizing is done in manual mode by AB, FCO, LBFCO. The implementation of capacity reduction is according to the criteria: - Ensuring transparency in implementation. - Ensure fairness, alternate performance. - Efficiency - The reduced capacity must be monitored; ensure safe and reliable operation of the power system, avoid overloading of transformers, lines, and situations that may lead to instability and unsafety of the power system.
Đak Lak PC	*(The same as Binh Thuan PC)*
Quang Nam PC	*(The same as Binh Thuan PC)*
Investors (BT)	Curtail on App of inverter / or by manual at site (open the MCCB or ACB)
Investors (QN)	The operation (monitoring and control) of the solar power system is done automatically based on the solution of ATS company and performed by electricity. Investors can monitor this software.

Topic 5:

Stakeholders	Curtailment
A0	(Topic not disccused)
A2	A2 exceptionally needs the data of the RTS system to forecast and operate the power system. A2 has not had real-time data of RTS until now. The collected data of the solar power plant are power, capacity, and radiation of the location close to the PV plants (not radiation data at the location of the solar power plant yet). The data of the PV plant is obtained from the SCADA system. The data of RTS system is obtained from the AMR of EVNHCMC and EVNSPC. A2 needs a database of large generators (wind farms, small hydro plants, ...) in the area. And the acquisition data include the weather information, U, I, P, Q, ...
EVNHCMC	The EVNHCMC is researching: - Researching and running a solution that is automatically curtailing the peak power of center DAIKIN. - Cooperate with SolarBK on a pilot project to test a solution of M&C for the RTS system. - Cooperate with Viettel to monitor and remotely control RTS systems by VCC device. EVNHCMC and A2 get the data at 110/22 kV busbar via the SCADA system. - EVNHCMC uses Load by Load Tap Change (OLTC) to control the Voltage of Load. The Automatic Voltage Control Level devices and OLTC were installed on 110/22 kV transformers.
EVNSPC	- The EVNSPC installed 2-way electronic meters for customers according to EVN's regulations. The meter has no remote-control function. If EVN requests installation of smart meters for RTS systems, EVNSPC will do it according to the regulation of EVN - We have no Policy or Request from EVN and MOIT for M&C of RTS systems. We essentially need it. - The EVNSPC installs equipment to collect data for all RTS systems which connect to the MV grid. EVNSPC is researching the technology of M&C for low voltage grid. - The EVNSPC has research and running demo by following the solution of 3rd party. This solution will connect M&C the inverter directly at the site. The problem is customers disagree with this regulation, so EVNSPC needs a regulation for this situation.

Binh Thuan PC	Binh Thuan PC has no overload due to the solar PV system. At the time when the solar PV is high, the transmission lines carry loads < 80% of the conductor rating. Pursuant to Circular 40/2014/TT-BCT dated November 5, 2014, of the Ministry of Industry and Trade on regulations on dispatching process of the national power system, the voltage regulation measures currently in use are: - Change the active/reactive power source of the compensator (capacitor, reactance) in order from near to far from the point where the voltage needs to be adjusted. - Adjust the transformer tap and regulate the electric equipment. Do not set step-up adjustment of the transformer (manually or automatically) to increase the voltage on the low- or medium-voltage side when the voltage on the high-voltage side is already below -5%. - Change the grid connection or reallocate the power trend in the power system (separate the low transmission line in case the high voltage exceeds the allowable limit and do not overload the remaining line). - Mobilize more backup power sources to generate or receive reactive power when the voltage is outside the allowable limit. - Shear the load to avoid voltage violations of the regulated low voltage limits.
Đak Lak PC	The Dak Lak power grid does not have an overload at all voltage levels. Voltage regulation below level 110 kV: Using voltage regulation at 110 kV transformers, adjusting the reactive capacity of small hydropower plants and on medium-voltage grids.
Quang Nam PC	No
Investors (BT)	If the Government requires to install M&C they must comply but the information should be shared with the investors so they can supervise together. The investor will not pay for anything.
Investors (QN)	*(Topic not disccused)*

2. Introduction to DERMS as a proposed remote monitoring and control solution

2.1. System overview

The distributed energy resource management system (DERMS) is built to provide the electricity company with an integrated and optimal solution for proactively monitoring and controlling energy flow and voltage of distributed energy sources (DER), meeting local grid operation conditions as well as capacity control requirements from Dispatch Centers and Power Corporations regardless of specific equipment and systems of each manufacturer.

With a distributed power generation sources collection, monitoring and control system, all the important information about the operation at the energy source including system characteristics, measurement data, status of the generators, integrated control, control function, warning function, etc. will immediately be connected according to standard protocol, collected and shared to SCADA system at Dispatch centers or Power company management centers, as well as execute control commands to comply with dispatching requirements.

The system is compliant by design with international standards, thus providing ready connectivity to other energy source systems and compatible with different Intelligent Electronic Devices (IEDs), controllers and data loggers from many manufacturers.

Supports integrated monitoring and control of a variety of distributed energy systems including:

- Rooftop Solar
- Small Wind Turbine
- Small Hydro Power Plant
- Diesel Generator (Genset)
- Battery Energy Storage System (BESS)
- Capacitor Bank
- Supports connection to controllable loads (implementing Demand Response)

Diversifying connectivity to devices of various manufacturers on RTS system including but not limited to:

- Inverter: Huawei, Sungrow, SMA, Sineng, ABB, TMEIC, Canadian, Solis, Goodwe, Growatt…
- Meter: Elster, Landis+Gear, EDMI, Vinasino, Schneider, Janitza…

The system also has an open-architecture design, allowing upgrades and additions of new functions, as well as integration with other systems in the future without significantly changing the system. Upgrading the system, adding new functions, and improving existing functions can be achieved by simple procedures.

2.2. System hardware structure

The hardware architecture allows flexibility in building hardware links, organizing software, organizing network access security, exchanging data internally in a distributed energy operation management system, and virtual power plant as well as connecting to external systems. With this structure, the Electricity Company can replace and upgrade each part of the system during future operation and expansion.

System hardware architecture (recommended) is shown in Figure 20, includes:

2.2.1. Central system structure

The main components of the central system structure are:

- 01 Front End Processor (FEP) server computer performs the function of connection management, collection, and processing of monitoring and control data from rooftop solar power sources, SCADA/DMS systems at Power Company, Power Corporations, A0/Ax Dispatch Center. Host computers are built to industry standards and operate under redundancy to ensure smooth, stable, uninterrupted system operation when a device fails.

- 02 Host Server computers perform the function of calculating and allocating capacity according to the requirements of operation dispatching, configuration declaration, a grouping of distributed energy sources, and running EMS problems. Host computers are built to industry standards and operate under redundancy to ensure smooth, stable, uninterrupted system operation when a device fails.

- 02 Operator Workstation, Historical Information System (HIS), and Engineering computers equipped with a Human-Machine Interface (HMI) system, allowing operators to perform monitoring and control functions for all distributed energy sources, perform the function of storing historical data to support the exploitation of operational management information, as well as the function of forecasting the generating capacity of the rooftop solar power system. In addition, this computer also plays the role of a technical computer, equipped with technical tools to assist operators in making reports, analyzing historical data, configuring and maintaining the system.

Switches (Ethernet switches), routers/firewalls establish LAN connecting host computers in the system and secure and encrypt data connections with external systems.

In addition, there are other peripheral devices to support the operation.

2.2.2. Site system structure

In distributed energy systems equipped with a Smart Controller device, the device will collect, centralize data and control on-site. The connection and transmission of monitoring and control data to the central system are done through a secure encrypted connection channel on the Internet/3G/4G network or optical fiber.

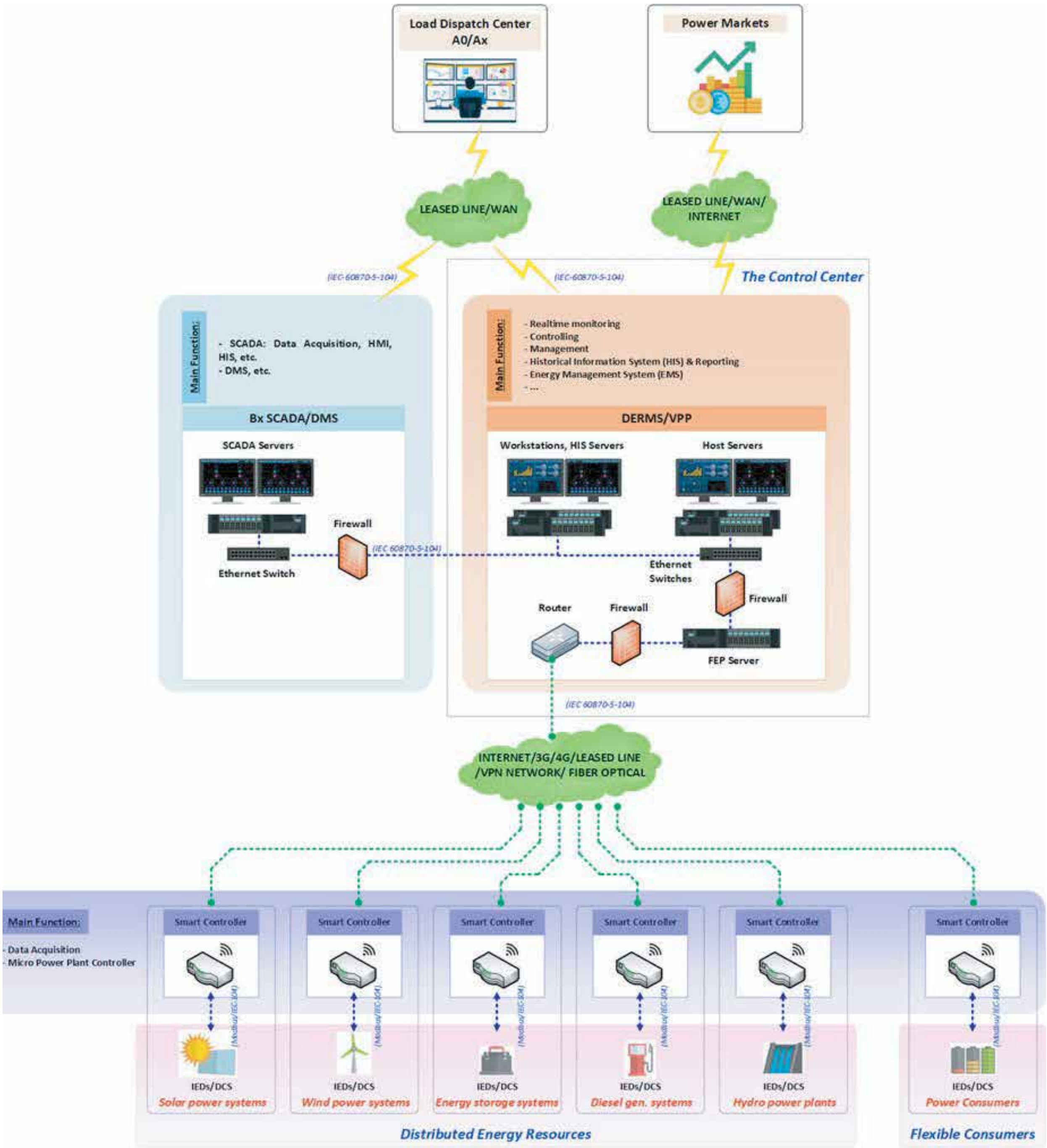

Figure 20. Recommended system hardware architecture. Adapted from [50].

2.3. Specifications of the Smart Controller

The Smart Controller device provides the ability to connect devices at the site according to standard protocols, and at the same time connect and share data about dispatching centers and customer operation information management centers through secure connection channel Internet/3G/4G VPN or optical fiber, performing on-site control functions RTS in particular and distributed energy sources in general.

2.3.1. Key features:

- Web-based configuration interface.
- Manage by list and on the map background.
- Ability to log and analyze activity (wave strength, device temperature).
- There are tools to send and receive AT commands, check network connection.
- Support the ability to update firmware, backup, and restore configuration remotely.
- Power indicator light, data exchange indicator with equipment, and operation indicator light.
- The device supports direct connection to the device according to the following protocols: IEC 60870-5-101/104, Modbus RTU/TCP, DNP3, SEL FastMessage...
- The device supports connection and data sharing with Dispatch centers, operation centers according to IEC 60870-5-104 or IEC61850 protocol.
- The device supports the "data buffering" function to ensure that data at sites is always shared to the data center in case the transmission channel between sites and the center is interrupted.
- Support the ability to connect VPN with operation management center
- Supports Port Forwarding function for TCP ports and Port Redirector for serial ports.
- Provides the ability to synchronize time according to the NTP protocol.

Suggested minimum equipment specification requirements can be found in Annex 1.

2.3.2. Device functions:

The Smart Controller device is capable of supporting device connection at site according to different standard protocols, so the distributed source collection, monitoring, and control system solution can be fully compatible with other systems, rooftop solar power systems, distributed energy sources of different manufacturers, as well as technical requirements of Dispatch Centers, Power Corporations.

The main functions (function blocks) include:

- Data Acquisition function block: Collects control monitoring data from the device according to standard protocols.
- Factory control function block (PPC): supports executing control commands from the DERM system, including
  - ◊ Active power control.
  - ◊ Reactive power control.
  - ◊ Power factor control.
  - ◊ Voltage control.
  - ◊ Monitor voltage.
  - ◊ Reactive power control is based on the voltage at the grid connection point.
  - ◊ Start-up and shutdown of the whole plant
- Gateway function block: Synthesize data, connect and share data with DERM/VPP, SCADA systems, operation information monitoring system at Dispatch Centers, Power companies, and private owners.

2.4. Support protocol

The Distributed Energy Operations Management System supports standard protocols such as:

- OPC UA: Internal data connection between software modules in the system
- IEC 60870-5-104/IEC61850/ICCP: Connecting data to monitoring and control systems at each distributed energy source and connecting to SCADA/DMS/EMS systems at the Electricity company, General power companies, dispatching centers.
- Modbus RTU/TCP: Connecting data from actuators at the Site such as Inverter, Data Logger, Controller...
- IEC 62056-21/Modbus RTU: Meter data connection.
- FTP (.xls, .txt): Supports file transfer of capacity allocation data.
- API/Web Services: Connect to collect weather forecast data.
- In addition, the system is ready to integrate other protocols widely used in the industry.

2.5. Operational performance of distributed energy source operation management system and virtual power plant

The distributed energy source operation management system is designed to ensure that the operational management system performance requirements are met relative to the number of rooftop solar PV systems within the current management scope and ready for future system expansion without the need to upgrade any additional system components.

2.5.1. System performance:

- Meeting management and operation of at least 300 rooftop solar power points.
- Meet the data collection, processing and storage of at least 75,000 data points and can be upgraded in the future.
- Support the ability to connect to at least 04 SCADA/DMS/EMS systems at Power Corporations, A0/Ax Dispatch Centers.

2.5.2. The ability to upgrade the system in the future:

- Ability to upgrade the system to expand operation management of rooftop solar power points without causing major hardware and software restructuring.
- Capable of upgrading data collection, processing and storage without causing significant system or program.
- Capable of upgrading connection to other SCADA/DMS/EMS systems at Power Corporations, A0/Ax Dispatch Centers and other centers.

2.6. Central system software structure

The distributed energy operation management system and virtual power plant at the center is designed with a structure consisting of small software blocks (modules) to create favorable and easy conditions for management and maintenance. maintain, upgrade, ensure the security and stability of the system.

The main functional modules of the system include:

- Data Acquisition (DA)
- Real-time data processing (RTDB - Realtime Database)
- Human-Machine Interface (HMI)
- Historical Information System (HIS)
- WEB-Based Monitoring (WEB-Based Monitoring)
- Calculate and retrieve payment invoices (Bill Payment)

- Data Analysis and Warning
- The function of predicting the generating capacity of the rooftop solar power system (Estimation/Forecasting).
- Function to control distributed sources:
  - ◊ Support for distributed source group control:
    - + Controls for entire sites, or for groups of sites
    - + Control the total capacity of the sites, each group of sites, each site separately according to the preset schedule.
    - + Controls for each site.
  - ◊ Support for control methods:
    - + Control by AGC command from SCADA/EMS systems
    - + Control according to the power generation chart (Schedule)
    - + Control according to the set value manually (Manual)
    - + Setpoint calculation mode (Calculation) to calculate and redeploy distributed sources in case of overload of transformers and lines
  - ◊ Control modes:
    - + Active power control
    - + Ramp Rate Control
    - + Voltage, power factor, reactive power controls
    - + Control modes according to grid operation requirements (Grid support)
    - + Start-up and shutdown of the entire plant
- Functions of the General Management System (Information Management System)
  - ◊ Register RTS to the system (Registration)
  - ◊ Managing the rooftop solar power group (Grouping)
  - ◊ Information Publishing
- Function to connect and share data with SCADA/DMS/EMS systems at Power Company, Dispatch Center (Gateway Interfaces).
- Asset management and system maintenance according to CIM model (IEC61968/61970)

2.7. Technical standards and regulations

Technical solutions and technical standards should ensure compliance with the latest version of domestic and international technical standards such as IS/IEC/IEEE; policies, regulations, and orientations for solar power development in Viet Nam; construction standards and national grid operation requirements. Key relevant standards are listed below.

International standards and regulations

- IEC 60870: Tele-control equipment and systems.
- IEC 60870-5-101/104: Substation communication protocols
- IEC 61850: Communication networks and systems for power utility automation
- IEC 61968 / 61970: interface architecture for Distribution/Energy Management Systems
- IEC 61724: Photovoltaic system performance.
- IEC 62446-1:2016, Photovoltaic (PV) systems - Requirements for testing, documentation, and maintenance - Part I: Grid-connected systems - Documentation, commissioning tests, and inspection.
- IEC 62446: System documentation, commissioning test and inspection…
- IEEE 2030.11: Guide for Distributed Energy Resources Management System.
- IEEE 1547-2018: IEEE Standard for interconnection and interoperability of Distributed Energy Resources with associated electric power system interfaces.

Vietnamese standards and regulations

- 54/2008/QD-BCT: National regulation on electrical engineering
- 12/2008/QD-BCT: National technical regulation on electrical safety
- Standards and regulations of MOIT and of EVN on the operation of the national power system.

Chapter 03

Recommended technical solutions on remote monitoring and remote control for RTS in Viet Nam

Chapter 3: Recommended technical solutions on remote monitoring and remote control for RTS in Viet Nam

1. Status overview

In Viet Nam's current context of high shares of solar PV, more than half of the installed solar PV capacity is from rooftop solar systems. RTS installed capacity grew in the last 2 years, from nearly none to 9,730 MWp reached in December 2020. Around 56% of that share is concentrated in the South of Viet Nam and 77% of nationwide installed RTS capacity is located at industrial customer premises (with an average of 482 kWp per system).

Remote monitoring and remote control of rooftop PV becomes necessary to contribute to maintaining grid stability and reliability. Experience and practices from the selected countries as Germany, Australia, USA with their long-standing development of solar PV have shown that remote control and remote monitoring of rooftop solar is recommended and applied broadly in fact. The electricity seller has responsibility to install remotely controlled circuit breakers/switches for the purpose of use in electricity security-related emergency cases. Rooftop solar units are requested to install mini-SCADA and data collection systems, and to share data and figures of electricity output, active power, reactive power and other technical parameters with the power utility in the locality. Remote monitoring of rooftop PV provides the DSO increased visibility to operate their system with increasing rooftop PV units and, combined with remote control, ensure rooftop PV can be integrated without compromising system stability and power quality increasing DSOs capability to balance the load.

With remote monitoring of rooftop solar PV and area forecast, solar PV curtailment can be reduced along with system operational costs, as dispatch will consider more accurately the generation from rooftop PV and hence improve management of power purchase from large generators. Remote control of rooftop PV allows the DSO to react faster to grid emergencies. Real-time monitoring of PV systems also allows for example participation in virtual power plants and market participation of rooftop PV.

The current status of rooftop solar systems and remote control and monitoring systems (M&C) were investigated via desktop research and meetings with the Vietnam National Load Dispatch Center, the Southern Load Dispatch Center, EVNHCMC, EVNSPC, Binh Thuan Power Company and Solar PV Investors in Binh Thuan province, Dak Lak Power Company and Solar PV investors in in Dak Lak Province, Quang Nam Electricity Company and Solar PV investors in Quang Nam province.

In addition, CIRTS project has also organized two consultation workshops in Ho Chi Minh and Da Nang city, in order to exchange, discuss and analyze in depth the impacts of RTS seen by different stakeholders and the recommended remote monitoring and remote control requirements for RTS in Viet Nam.

Through the above activities, issues related to RTS systems were identified and include:

Technological - technical issues:

- The units are equipped with monitoring system of load break switch (LBS) and self-closing circuit breaker (recloser), there is no remote control system for PV systems connected to medium voltage grid.
- There is no real-time data collected from RTS. Data from Automatic Meter Reading (AMR) clock is updated periodically.
- There is no remote monitoring and remote control capability required for PV systems connected to the low voltage grid.
- Currently owners of PV systems monitor their systems using applications of inverter manufacturers.
- A number of projects are piloting the installation of remote monitoring and control systems, such as the one at Quang Nam Power Company.

Legal framework issues

- The form of connection agreement and power purchase agreement does not contain any requirement for system investors to install PV systems with remote monitoring and remote control capability.
- There are no requirements in grid code and technical standards for the installation of rooftop PV systems with remote control and remote monitoring capability.

Operational issues – human resources issue

- The Power companies depend on the NLDC when calculating and forecasting the mobilized capacity. Curtailment shares are defined using one week ahead forecasts, to leave sufficient time to negotiate with system owners for curtailment.
- Operation coordination is done based on the Agreement with system investors. Therefore PCs are faced with the challenge of lack of cooperation of a few system investors. Additionally, system investors do not have qualified personnel to operate the RTS system.
- Electricity of Viet Nam (EVN) does not have sufficient human resources to deal with uncooperative system investors.
- EVN does not have sufficient human resources to enforce curtailment of PV according to the mobilisation schedule when system investors do not perform the requested curtailment.
- In the context of rising RTS shares in the total generation mix in Viet Nam and the curtailment share of RTS being calculated by A0 and being passed on to Ax and PCs, it is important to increase cooperation and data sharing for increased coordination between the transmission and distribution system operators.

Considering the above identified issues, the main conclusions about the remote monitoring and remote control system of the RTS are:

- Currently, limited remote monitoring and control (M&C) systems present at the distribution level (LBS and recloser) do not meet the requirements for safely coordinating the operation of the power system with increasing RTS shares. M&C systems for RTS systems are not popular yet and limited to a few pilot projects.

- The current M&C system is not able to monitor the curtailment or mobilization of rooftop solar power capacity, for example to check if a curtailment request has been implemented at a specific RTS system.

- The current M&C system is not enough to effectively control rooftop solar power (active and reactive power, ramp rates, etc) of larger systems when necessary. For example, providing grid support via remotely adjusting reactive power settings – voltage support- and remotely adjusting active power feed-in – support during grid overload).

- The current M&C system does not have enough operational information to report and support with dispute resolutions, which increases the challenge to ensure criteria such as “reasonable, transparent and fair” for investors.

The lack of remote monitoring and remote control solutions for RTS today is a consequence of the lack of legal and technical requirements for such in Viet Nam, coming from a time when there were only a few RTS installed. There are no mandatory regulations/legal requirements for setting up remote monitoring and control systems for medium and low voltage grid connected RTS systems today, therefore only a few of such systems have been installed to date. This results in the challenge for the system operator of having little or no visibility nor controllability of RTS systems’ feed-in in the current context of high RTS penetration. Some RTS systems have a M&C solution installed (at the system investors’ stations) however such systems are not connected to grid operators’ management systems to allow for their remote control and real time monitoring functions. Furthermore, requiring new RTS to have the capability of being remotely controlled and having their active power feed-in remotely reduced in emergency situations requires clear curtailment rules and conditions established in the regulations.

2. Recommendations

2.1. Technical recommendations for remote monitoring and remote control capability and implementation options

- It has been observed in the international practice of countries with high rooftop solar share (Chapter 1) that facilitating remote monitoring is a requirement for PV systems above 200 kWp (or already above 100 kWp in Germany's example). It is recommended to require rooftop PV systems above a certain size in Viet Nam to be capable to be remotely monitored. The initially required size can be gradually reduced over time with increasing PV penetration in the system.

- The majority of RTS total installed capacity in Viet Nam consists of systems of 500 kWp and above. At minimum systems of 500 kWp and above should be capable of being remotely monitored and controlled.

- Different options to achieve increased visibility in the distribution level exist:

    ◊ [existing solution] The automated meter reading (AMR) solution (reads export and import) already existing today covers around 49% of the meters and was planned for 100% coverage by 2022 . Used technologies are GPRS/3G, PLC, RF. It does not offer real-time monitoring, a sample rate of 30 minutes typically applies.

    ◊ [short-term solution] Access data from inverters using a communication device that is connected to the internet.

    ◊ [long-term solution] Smart meters, which during the data collection phase were indicated to be a long-term solution for Viet Nam.

- Forecasting of RTS and other renewable generation by distribution area is recommended to be done by the DSO. Daily forecasting of both load and renewable feed-in in the distribution grid is within the responsibility of either the DSO or the TSO (depending on the country). If at least a few rooftop PV systems are monitored in real-time, data from these PV systems can serve as a reference to estimate the output of nearby PV systems. In the absence of real-time data from PV systems, physical power models can be used based on weather data and assumptions made about the characteristics of the installed systems.

- The capability of being remotely disconnected is a minimum requirement in all countries reviewed that already have high RTS shares. An additional requirement is in place to reduce feed-in to certain levels based on the PV system size (e.g. PV systems >100 kWp in Germany are required to be capable of reducing active power feed-in to 4 levels). Therefore, it is recommended to further investigate the possibility of requesting rooftop solar systems above a certain size in Viet Nam to be capable of being remotely disconnected or having their feed-in to the grid reduced in case of grid emergencies. Different options can be explored to achieve this:

  - ◊ [short-term solution] Communication device connected to the inverter to enable to remotely disconnect the system or change the inverter output levels to for example 0%, 30%, 60%, 100% (such as in the German example).

  - ◊ [Medium to long-term solution] Smart meters that have digital outputs can switch relays and remotely disconnect the RTS system or reduce its active power feed-in, given that bi-directional communication infrastructure through a secure smart meter gateway is existent.

  - ◊ [Medium to long-term solution] Update grid codes to require inverters to have internet communication capability. It would allow for advanced functionalities and hence more fine-tuned control, such as updating grid code settings and changing inverter output to a specific percentage, rather than in 4 predefined steps (thus reducing curtailment).

- Performing remote monitoring and remote control of all rooftop PV systems regardless of size by the DSO is unnecessary and expensive. Therefore, the recommendation following international good practices is to require RTS systems above a certain size to be capable of being remotely monitored and/or remotely controlled (at minimum being capable of being remotely disconnected) and let the DSO decide whether to establish the communication link to each RTS system or not in order to make use of such capabilities based on need (link for example to a DERMS).

- The most suitable physical media needs to be selected based on the grid architecture of each DSO in Viet Nam and local rules (for example regarding the use of the frequency spectrum). Options used internationally include: GPRS/3G Cellular media, PLC, RF and Low Power Wide Area Network (LPWAN).

- It is extremely important to have standardized communication protocols to enable interoperability between the utility and the various DERs, while also ensuring the security of information flow. Proprietary protocols may create an additional barrier to integration. Internationally recommended protocols are SunSpec Modbus, IEEE 1815, IEEE 2030.5, or IEC 61850.

- It is recommended to have standardization not only of the communication protocol but also of the specification of data acquisition hardware, processing, etc., for future interconnection, to facilitate a centralized monitoring system. Parameters to be monitored and how these will be integrated with the monitoring Centre should be clearly specified.

- Remote controlling active power feed-in requires well-established rules for curtailment. International good practices indicate that curtailment of RTS systems should be limited to emergency situations and the need justified to the RTS system owners upon request.

- Suitable security measures must be investigated for physical security, communication interface security, and network security.

2.2. Proposed DERMS solution to implement remote monitoring and remote control in Viet Nam's considering current regulations

Similar to other solar power sources (ground solar power, floating solar power, etc.) RTS systems also need to be sufficiently monitored, forecasted generating capacity and mobilized capacity according to the order of dispatch to ensure that the operation of the power system is continuous, safe and reliable. According to international experience and lessons learned from countries that have reached high shares of RTS generation in their system (Germany, the United States, Australia), establishing technical requirements for monitoring and remote control capability of RTS systems is recommended.

"Guidelines on technical requirements for solar PV inverters" issued under Official Letter No. 4304/ĐĐQG-PT October 2021 contains basic technical requirements for PV systems. However, these requirements only apply to RTS systems with an installed capacity of over 500 kWp and connected to the medium voltage grid. Currently, there are no detailed technical requirements for RTS systems connected to low voltage grids. In particular, there are no specific requirements for remote monitoring and control in the Guidelines for RTS systems connected to the medium voltage grid.

According to the Circular No. 40/2014/TT-BCT dated November 15, 2014 of the Ministry of Industry and Trade, currently the medium voltage grid (from 35kV or less) is under the control of the distribution dispatching level (the provincial/municipal dispatching level) therefore the dispatching command of the distribution grid including RTS systems is under the control of the Distribution Dispatch Level.

According to Decision No. 55/QD-DTDL dated August 22, 2017 of the Electricity Regulatory Authority of Viet Nam, the SCADA/DMS system is now equipped at the distribution dispatching level (province/municipal dispatch department) to monitor and remotely control 110 kV and 35/22 kV power grids in provinces/cities, therefore equipping DERMS systems at provincial/city dispatching rooms to dispatch power distribution grids and share data for SCADA/DMS/EMS and control of the RTS systems is the most suitable model. In the case of building a centralized DERMS system, a new department will be established to manage operations, the centralized DERMS system must connect many RTS systems in different localities and handle large volumes of data. As technology continues to grow, new types of distributed sources and flexible loads will connect to the centralized DERMS system, which might lead to the overload of the system. Furthemore, for the centralized DERMS system, when the system fails, connection and control of a larger number of systems will be lost compared to a decentralized/provincial approach.

The Ministry of Industry and Trade is the agency that promulgates regulations on technical requirements for DERMS, data communication systems and smart controllers. EVN and system investors are to act accordingly to the law.

A potential model of remote monitoring and control of the RTS systems and distributed sources via a DERMS was introduced in Chapter 2 and in the workshop with stakeholders (shown in Figure 21). DERMS includes at least (and not limited to) functions such as:

- Management of RTS system owner information.
- Collect real-time data to monitor, analyze and forecast the output power of the RTS system.
- Sharing data to SCADA/EMS/DMS system and receiving data from AMR/AMI system.
- Capability of controlling the output power (fine control or e.g. 4-level control).
- Capability of controlling the increase (when previously curtailed)/decrease of the output power of each inverter/each region/each zone.
- Ability to disconnect and re-establish connection remotely.
- Capable of connecting with devices of many different manufacturers according to the specified protocol.

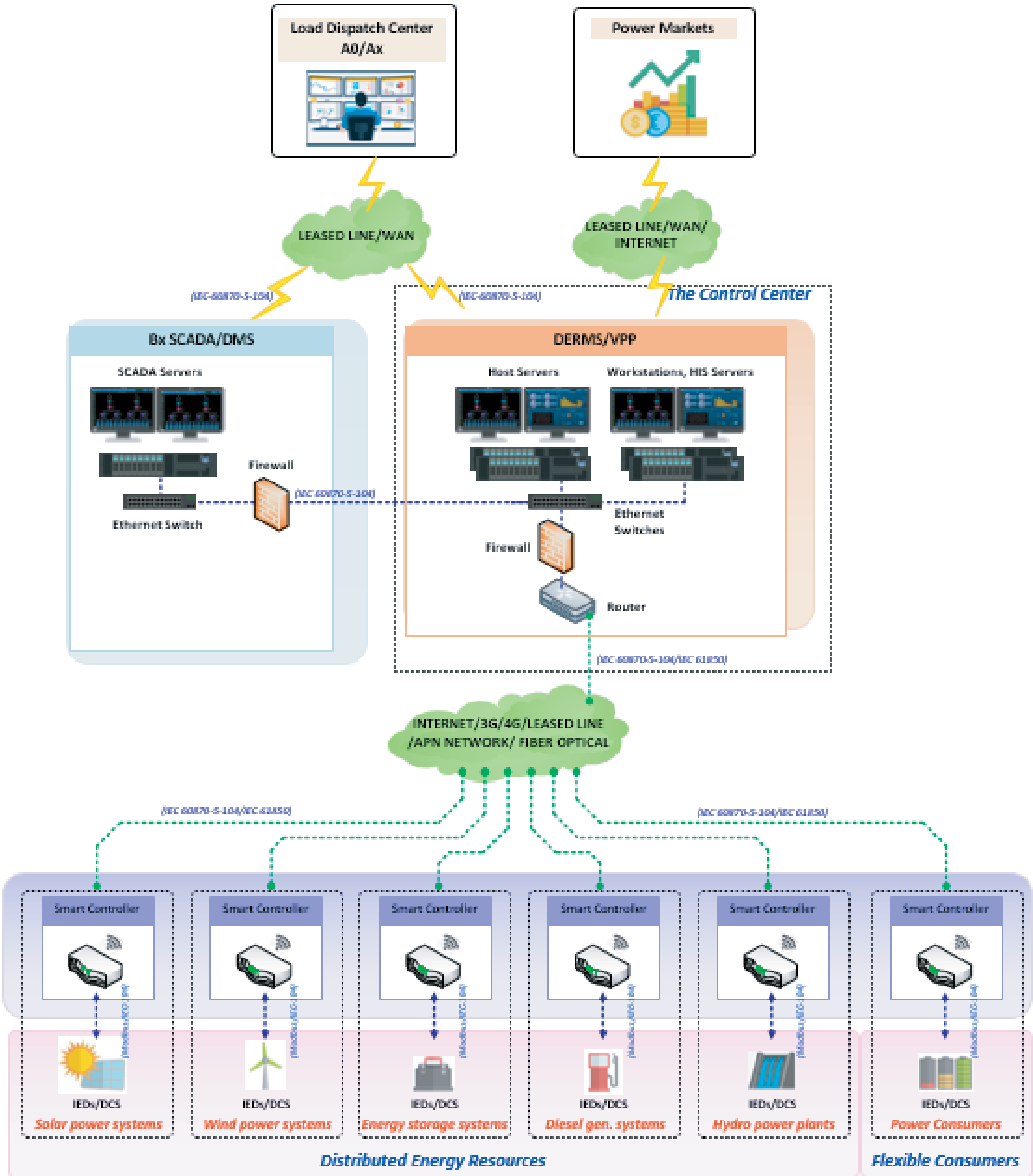

Figure 21. Structure of M&C for distributed energy resources. Adapted from [50]. Introduced in an extended version in Chapter 2

Recommendations for a DERMS solution for Viet Nam include:

- Data transmission system: Recommended to use the IEC 60870-5-104 protocol specified in the decision No. 55/QD-DTDL dated August 22, 2017 as the communication protocol between smart controller/smart meter devices. and the DERMS system. Recommended to use the APN 3G/4G transmission channel specified by EVN as a transmission channel from smart controller/smart meter devices and DERMS system.

- Smart controller/smart meter: Collects data from RTS system according to standard protocols. Recommended to synthesize data, connect and exchange data with the DERMS system using the IEC 60870-5-104 protocol. It should support the execution of control commands from the DERMS system including active power control; voltage control, power factor, power increase/decrease ratio control, start-up and shutdown the whole system.

- The applied solution should be designed to ensure network security and information safety according to regulations of EVN and the Ministry of Information and Communications.

2.3. Implementation speed

Certain grid areas in Viet Nam have already reached high RTS penetration, for such areas a faster and targeted solution to increase visibility and control at the distribution level might be necessary whilst expert groups design and develop an advanced solution including required adaptations to regulations. Such fast and targeted solution would apply only in targeted areas where there is a critical need for remote M&C already at present and apply only for selected larger RTS systems (for example apply to new[23] installed RTS systems above 500 kWp), as shown in Figure 22.

The PV system can be configured to receive control signals by the means preferred by the DSO, with recommended means including ripple control and GSM/GPRS. Furthermore, the fast/targeted solution should be designed so that participating systems can later be included in the advanced solution without significant changes/costs.

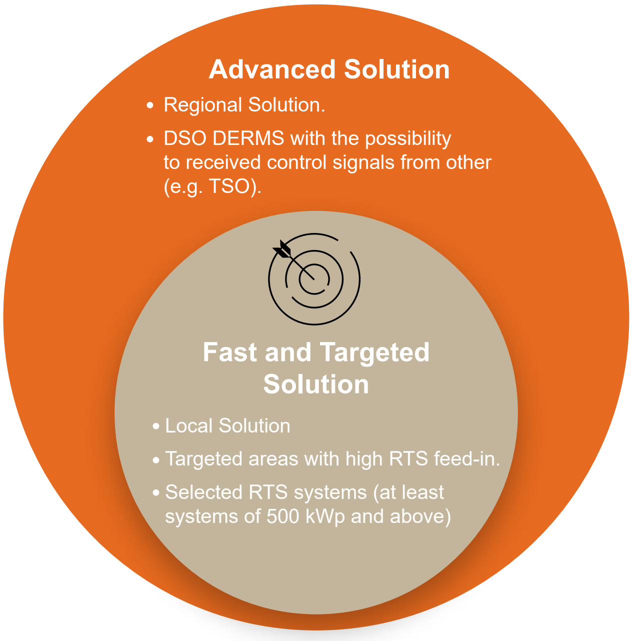

Figure 22. Proposed implementation steps for a remote M&C solution.

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23 It is recommended to apply requirements to RTS systems that are installed after the requirements come into force, i.e. it is not considered international good practice to apply requirements to already installed systems.

2.4. Supplementing Circulars and Regulations

Considering the risk to the grid posed by the lack of requirements for the capability of remote monitoring and remote control of RTS systems, it is strongly recommended to develop a complete and detailed legal regulation/requirements for the establishment of the monitoring system and remote control for the grid-connected RTS system. It is recommended that new circulars and regulations are supplemented and further developed as follows:

- Supplement Circular 40 with regulations on decentralization of control of RTS sources under the control of the province/city dispatching (DSO) as well as regulations for distributed energy sources (RTS, wind, biomass power, energy storage system, etc.) that increasingly penetrate the distribution grid.
- Supplement Circular 39 with standards for connection of RTS sources to medium and low voltage grids and regulations on setting grid codes for RTS systems as well as regulations regarding compliance to technical standards. Supplement with the responsibilities of RTS investors in participating in the grid dispatching work (providing information for contact, having a trained team to coordinate operation,..), monitoring and controlling solar power systems.
- Include in regulations minimum technical standards for the RTS system, specifically standards related to PV panels, inverters, grounding systems, remote control systems for solar PVs, monitoring equipment.
- Include in regulations requirement for remote monitoring and remote control capability initially for larger RTS systems (recommended to be at least those with capacity over 500 kWp as it was identified that the majority of RTS systems total installed capacity consist of single systems of 500 kWp or more). This limit can be reduced gradually, and based on need, in areas that reach higher RTS shares. An implementation roadmap is proposed in Section 4.
- Develop regulations related to the dispatching, monitoring and control of the RTS system wherever a DERMS is applied, including:
    - ◊ Regulations regarding data sharing to Ax and A0, data sharing to investors (if they have demand). In addition, the DERMS can act as a backup system for the existing monitoring system (monitoring through the inverter manufacturer's software) of the Solar PV investors after the warranty period expires, as the supplier companies will no longer be responsible and the ability to monitor RTS system by the system owner may be lost.
    - ◊ Regulations on providing real-time data of the RTS system to Ax (A1, A2, A3) to improve efficiency in real-time planning and operation.
    - ◊ Regulations on the scope of investment in the DERMS system, equipment, transmission channels, protocols, costs, etc. to connect and monitor and control the RTS system.
    - ◊ Regulations on ensuring data security and privacy of Solar PV investors and operation security of the power industry

- Develop regulations to ensure sufficient capacity building for dispatchers, operation management staff of power stations and operators of RTS systems.

- Develop regulations on curtailment of renewable energy sources (i.e. reduction of active power feed-in to the grid) including (emergency) conditions where curtailment is allowed, regulations on implementation limits of curtailment, measures to verify whether the system has carried out the requested curtailment, cost recovery for system owners (if any).

- Having remote control on at least the larger RTS systems will allow to reduce the forecast window used for the calculation of curtailment shares and therefore achieve a more accurate calculation of curtailment shares, minimizing the curtailment from RTS. However, for those RTS systems of significant size which are not capable of remote active power control, it is recommended to review the strategies of stakeholder engagement in curtailment actions, to develop strategies to minimize the curtailment from RTS and at the same time maintain fairness of the request to curtail among different PV owners (e.g. equal curtailment percentages for all systems in the affected area or a rotational scheme).

- The Seller is responsible for coordinating the Electricity Buyer (EVN) to connect the RTS to the DERMS. If the electricity seller fails to comply with the regulations, it is recommended that the electricity buyer is entitled to disconnect the RTS system.

- It is recommended that the Seller is responsible for the investment, installation, operation and maintenance of smart controller/Smart meter equipment, data transmission equipment (modem) installed at the Seller's side and also the transmission channel (e.g. 3G/4G) from the PV system to the DERMS of the dispatching level with control authority. It is recommended that the Buyer is responsible for the investment, installation, operation and maintenance of the DERMS and the modem installed at the Buyer's side.

- The DERMS is recommended to be installed at the dispatching level with control authority. The technical requirements of the DERMS should comply with the regulations promulgated by the Ministry of Industry and Trade.

- The DERMS can share data for the SCADA/EMS/DMS system and the rooftop solar power system investor connected to the DERMS. In this case, this should be reflected in the regulations.

- Develop regulations on coordination of operation and troubleshooting between the operator and the owner of the Solar PV (clearly specifying the functions and duties of all parties involved, the operator will check the operation ability according to the regulations in the connection mechanism/standards, etc.)

- Develop a regulation to limit or stop the installation of relay F81 (sheds load) on certain medium voltage feeders with significant RTS shares (see section 3.4).

3. Additional considerations

3.1. Cyber security aspects

Modern rooftop PV inverters have several operation modes that help improve overall system reliability. Key operation modes include constant power factor mode, limit active power mode, constant reactive power mode, voltage-reactive power mode, voltage-active power mode and active power-reactive power mode. Through remote monitoring capabilities, these operation modes can be activated/deactivated, and their parameters can be adjusted.

Considering these operation modes, attackers could inflict multiple types of damage to the distribution system if they seize control over one or multiple rooftop PV inverters or other types of Distributed Energy Resources (DERs) through a cyberattack. The physical impacts on the distribution system include frequency and voltage deviations, reduced grid efficiency, grid assets overload, disconnection of the DERs, loss of load and damage to electrical devices.

Attackers can seize control of DERs by gaining unauthorized access to the systems which are responsible for communicating with and controlling DERs. Attackers will take advantage of any cyber vulnerability present in the system to evade security systems and gain access to information and control services. Table 14 includes a list of some of the most commonly known cyber vulnerabilities. [51, 52]

Table 14. Commonly known DER cyber vulnerabilities. [51]

Cyber vulnerability	Description
Man in the middle (MITM)	An attacker gains access over a communications channel between two devices in the system so the data flowing through the middle node between the devices can be read, modified or deleted.
Eavesdropping	An attacker acquires data as it is transmitted thus stealing the information. The data could be used for malicious purposes once acquired.
Replay	A command being sent is copied by an attacker. This command is then replayed by the attacker to cause malfunctions.
Weak passwords	Attackers, whether software or a human, could continually attempt to guess user passwords. This is also known as a brute force credentials attack. If user passwords are weak, attackers have a better chance to guess the password and gain unauthorized access to the system.
Denial of Service (DoS)	The attacker attempts to overload the communication network, limiting system availability and preventing authorized system operators from having access to system monitoring and control functions.
Spoofing through security certificates	Attackers with unauthorized access to public key certificates used to authenticate authorized clients could potentially gain access to the system and perform a data modification attack.
Lack of least privilege principle	Authorized system users should only have access to the information and functionalities needed to perform a specific task. If this principle is not applied and an attacker gains unauthorized access to the system, the attacker could potentially manipulate all information and functionalities present in the system.

Currently, cyber security requirements of specific DER deployments can vary across jurisdictions. There exists several international cyber security standards and guidelines that may be applicable to DER deployment. Among these standards and guidelines, the most recognized ones include DNP3-SA, CSIP, IEC-62351, ISO/IEC 27000, IEEE 1686, NERC CIP, NISTIR 7628 and IEC 62443. [53] Based on the cyber security vulnerabilities outlined above, advanced and basic guidelines to improve DER cyber security were proposed by NREL and are shown in Table 15.

Table 15. Basic and Advanced Security Control Guidelines [54]

Level	Security Controls
Basic Security Controls	• Network segmentation—By segmenting information technology (IT), operational technology (OT), and management networks[24] with access-control lists that avoid broadcast storms and establish hyper-quiet data links for effective intrusion detection, damage can be contained if one of the networks is compromised. • Systemic security—Secure the network systemically by implementing context- and signature-based intrusion detection and intrusion prevention systems as well as inline blocking tools. • Inline-blocking devices—To protect critical nodes from unauthorized access in a SCADA system within the OT network, inline blocking tools with transport layer token authentication and data diodes with hardware layer filtering of Modbus TCP messages can be used. • Intrusion-detection systems—Use context-based and signature-based ID/IPS for network-based anomaly detection and business process security. • Selective encryption—Encryption creates an overhead for resource-constrained device communications where latency might also be critical. Therefore, selective encryption of the data will help utilities to minimize the processing overhead and application latency. Use of public key infrastructure (PKI) and digital certificates is preferred to guarantee a chain of trust using software and hardware policies. • Role-based access controls (RBAC)—Use access-control lists on networking switches with strict restrictions on the traffic based on the need to minimize unauthorized access of network devices, power systems appliances, and IT servers. • Port security—All used ports should be locked in by the media access control (MAC) addresses of authorized devices with initial connection to avoid device swapping for cyberattacks launched from inside the trusted networks of the organization. Also, disabling all unused ports on the firewalls and switches to eliminate unauthorized access is a sound practice. • Patching—Any out-of-date critical infrastructure creates vulnerabilities that can be exploited. By making periodic updates of software security patches, cyber-risks from known vulnerabilities of older software versions can be mitigated.

24 Automated systems such as relay protection systems, automated billing systems and automatic control systems are examples of IT, whereas wind turbines, solar arrays, building control systems, and supervisory control and data acquisition (SCADA) systems are all examples of OT systems. Management networks refer to advanced network management systems used to monitor and control devices on the distribution system including DER and customer loads.

	• Least privilege—Give users access only to those applications they need to perform assigned tasks. • Visualization—Real-time monitoring dashboards that interactively visualize system events and logs ingested from heterogeneous devices in the DER ecosystem provide situational awareness. • Multi-factor authentication—Two-factor authentication gives users an added layer of security. • Strong usernames and passwords—All networked devices must be capable of avoiding brute force and dictionary attacks from hackers both outside and inside the network, which can be enforced using strong username-password combinations.
Advanced Security Controls	• Activate transport layer security (TLS) in DER devices such as smart inverters and microgrid controller systems. • Implement session resumption when the session is severed for a time less than the TLS session resumption time by using a secret session key. • Implement session negotiation when the session is severed for a time more than the TLS session renegotiation time. • Use a message authentication code. • Support multiple certification authorities. • Terminate the session if a revoked certificate is used to establish the connection; this is done using a certification-revocation list. • Identify and terminate the session if an expired certificate is used to establish the connection.

Most industry efforts on cyber security for PV inverters focus on data in transport to create a secure path for data between communication devices. A summary of cyber security requirements for different communication protocols are shown in Table 16. [55]

Table 16. Trust and cryptography features in common DER communication protocols. [55]

Protocol/ Security	Encryption	Node Authentication	Certificate/Key Management Notes
EIC 61850/ IEC 62351	IEC 62351-3 requires TLS	X.509 Digital Certificates	IEC 62351-9 covers generating, distributing, revoking, and handling public-key and symmetric keys for groups (GDOI) but does not define the type of keys or cryptography
IEEE 1815/ DNP3-SA	VPNs and IPSec are recommended. TLS is optional. Multiple TLS cipher suites are permitted, but TLS_RSA_WITH_AES_128_SHA shall be supported at minimum.	X.509 Digital Certificates	IEEE 1815-2012 allows pre-shared keys but also includes methods for symmetric and asymmetric cryptography.
SunSpec Modbus	None	None	None
IEEE 2030.5/ CSIP	EEE 2030.5 requires TLS. AES-128 in the Counter with Cipher Block Chaining – Message Authentication Code Mode shall be supported	X.509 Digital Certificates	IEEE 2030.5 requires key management by a public key infrastructure which shall use Ephemeral Elliptic Curve Diffie–Hellman key exchange with Elliptic Curve Digital Signature Algorithm signatures (ECDHE_ECDSA)

Additionally, in order to fully utilize DER remote monitoring and control functions, it is essential for DSOs and TSOs to acquire closer coordination. This includes the exchange of different types of data and increased level of observability and requires also cyber security measures to ensure the security of the data exchanged. [56] [57]

3.2. Virtual Power Plants versus DERMS

A Virtual Power Plant (VPP) is a virtual single entity representing an aggregation of distributed resources which together create an installed capacity comparable to a single traditional power plant. This aggregation enables the provision of services and participation in markets which are not typically open and/or feasible for smaller units. The distributed resources are controlled remotely using a centralised system to optimise the operation of all connected units and therefore requires smart meters and communication infrastructure, as well as accurate data (e.g. weather forecast, electricity prices in the wholesale market, etc). Optimization of the VPP operation can be done based on historical and forecasted demand, generation, and price data. VPPs therefore represent a mean to provide local flexibility to the distribution system from smaller units.

Aggregators operate several grouped DERs (for example within a VPP) to act as a single entity in the power market. Aggregators typically participate in the wholesale and retail market or through procurement of the distribution system operator. Having a liberalized power market which allows the participation of aggregators is therefore an enabler for their establishment. In Viet Nam, the electricity market is in general dominated by EVN (state-owned Electricity of Viet Nam). However, the government aims to develop a competition-based generation, wholesale and retail market by 2023.

Services which can be provided by VPP include but are not limited to: demand-side management, peak demand management, deferred investments in distribution assets, operational reserves, energy arbitrage, frequency regulation and other services which provide local flexibility.

Requirements for the establishment of a VPP include:

- Favourable market and regulatory conditions, such as being able to participate in wholesale electricity market and ancillary services market. Time of use tariffs also contribute to a favourable environment for the creation of VPPs;
- Real-time data acquisition from participating units as well as having controllable units (via smart-meters, two-way communication infrastructure, remote control, automation systems, etc);
- Forecasting of generation and load for optimising dispatch of participating units.

The conditions for a formation of VPP can be defined for each system, based on system needs and market characteristics.

VPP and DERMS solutions share common capabilities such as DER registration, aggregation, forecasting, real-time monitoring and control, optimisation and dispatch. However, a few capabilities and especially the use cases and intent differ. Key differences include [58, 59]:

- A VPP solution has a commercial/economic market focus and the benefits are system-wide. A VPP performs active power control across a fleet of assets (geographically dispersed and aggregated and presented to the utility or grid operator as one dispatchable resource) to provide grid services that are not highly depending on the specific location of individual assets like feeders or circuits. DERMS solutions have a grid operation focus and the benefits are more specific to selected distribution feeders/circuits, allowing for more precise and local-level control.

- The establishment of a VPP requires favorable market conditions, including the allowance by the regulation of VPP participation in the wholesale electricity market and in the ancillary services market. This is not a requirement to establish a DERMS solution.

- VPP provides capabilities for market participation (bidding, communication) and commercial settlement (verification, billing). DERMS provide capabilities for Volt/VAR optimization and active power management.

- VPP solutions are used to support use cases such as offering new products and services to energy consumers, participating in energy markets and utility demand response programs, and providing frequency regulation services to transmission system operators. DERMS services include voltage management, optimal power flow and locational capacity relief.

- In a DERMS solution, integration of DER with the utility is required, typically done through a DMS, ADMS or SCADA system. DERMS require more back-end system integrations than VPPs, due to the direct link to each connected DER, which leads to higher initial investment costs.

In order to determine whether VPPs and/or DERMS make the most sense initially in RTS hotspot areas of Viet Nam, the issues that currently occur associated to increasing RTS feed-in must be identified and quantified. VPPs will provide grid services which are not dependent on the specific location of each asset, whereas for more precise and location specific active and reactive power control, the DERMS is more suitable. It is common that utilities begin the journey to DERMS with first establishing VPPs and later gradually enabling assets within a DERMS platform.

Furthermore, the DERMS solution needs to be customized and integrated with the existing/ additional management systems within the distribution level. One important integration is between the DERMS and an Advanced Distribution Management System (ADMS) system. The ADMS is the software that supports the full suite of distribution management and optimization. To the ADMS other management systems can be integrated such as DERMS, which focuses on management of distributed energy resources, and also the outage management system, customer information system, as shown in Figure 23. [60]

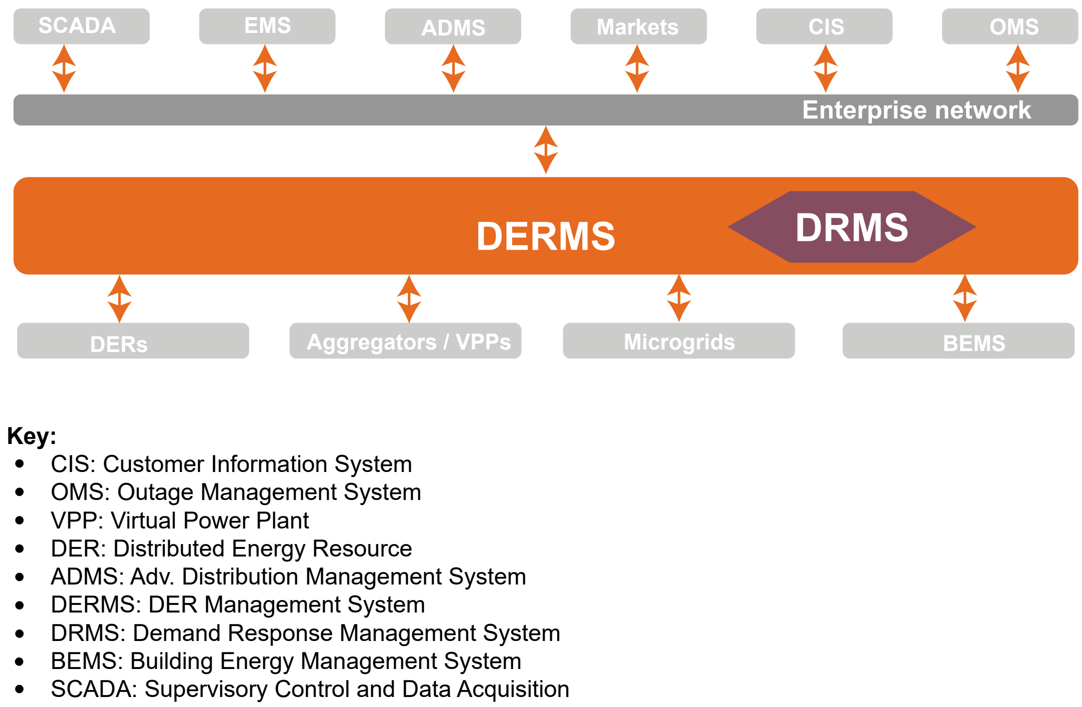

Figure 23. DERMS integration to ADMS and other management systems within the distribution grid. [61]

3.3. Recommendations towards technical requirements for PV systems in LV and MV

3.3.1. Recommendations based on international best practices

Impacts of high RTS shares on the grid can be mitigated via basic settings in the RTS inverter, which can be required via regulations/grid codes. These allow the inverter to autonomously provide grid support, and are already available in many inverter models (i.e. at no additional cost).

It is recommended to continuously improve technical requirements for RTS inverters connected to the LV or MV in Viet Nam, using international best practices as reference from countries which have already reached significant shares of RTS such as Australia, Germany and USA (California and Hawaii). Recommended capabilities to be required for DER inverters that not only mitigate DER related impacts but also provide grid support include:

- Low/high frequency ride-through
- Low/high voltage ride-through (L/HVRT)
- Frequency response (Frequency-Watt)
- Reactive power capability
- Reactive power control modes (e.g. constant power factor, Volt-Var mode, Watt-Var mode)
- Active power control modes (Volt-Watt)
- Ramp rate limitations
- Logic interface for communication capabilities

Furthermore, technical standards will not be effective if a compliance mechanism is not set in place and adequately applied. RTS systems should be required to certify that they are capable to perform all the operations that are required in the grid code/standards and respond in a timely manner to communication. For example, compliance can be ensured through type testing (as used in the US for DER in standard IEEE 1547.1).

Developing technical requirements is a continuous process, which often starts with essential requirements, based on international experience, that are later refined and expanded to better reflect the needs of the system using more detailed simulation studies (as shown in Figure 24) as well as consulting manufacturers to identify the capabilities of existing products and evaluate potential costs of extended capabilities. [62]

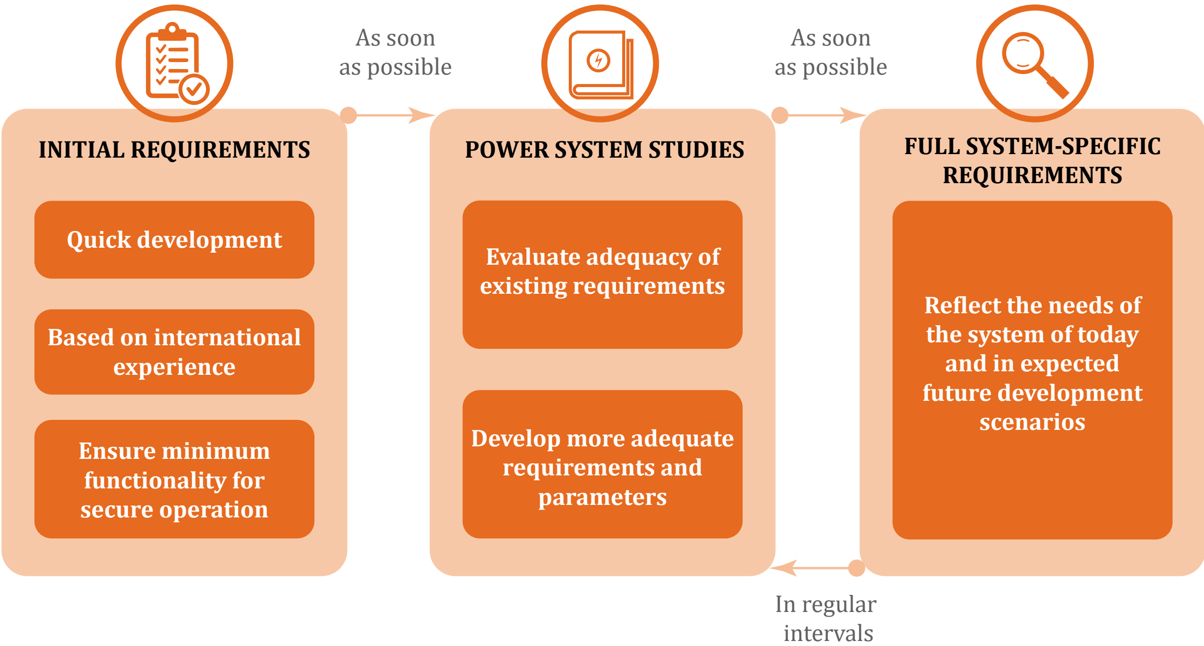

Figure 24. Parameter development and revision process. Source: [62].

3.3.2. Comments to 2022 draft circular amending Circular 39/2015/TT-BCT

This section provides a brief review of a set of proposed changes to Circular 39/2015/TT-BCT dated 18/11/2015, based on unofficial translations by GIZ. Among the proposed changes, the review focuses on the modifications to articles 40, 40a, and 42.

Summary of proposed changes in Articles 40, 40a, and 42

- Article 40 no longer applies to all solar PV (and wind) power plants connected at the medium voltage level; it also requires a minimum power capacity of 1 Megawatt to be applicable.
    - ◊ The requirements in Article 40 are expanded. New requirements related to dynamic voltage support, post-fault active power ramping behavior, and withstand capability regarding rate of change of frequency as well as voltage phase jumps are introduced.
- A new Article 40a is introduced to specify the requirements for solar power plants connected at the medium voltage level with 1 Megawatt and less power capacity.
    - ◊ The new Article 40a is based on the technical requirements for solar power plants connected at the low voltage level.
- Changes in Article 42 clause 2 appear to be clarifications only, with no obvious significant change in meaning.

Observations and remarks

The proposed changes essentially relax the technical requirements for solar systems of 1 Megawatt and less connected at the medium voltage level. While previously the set of requirements for these power plants would have been the same as described in Article 40, the newly applicable requirements are now closer to those specified in Article 41. The new requirements are relaxed compared to the previously applicable ones in that:

- active power control (dispatching limit) capability is no longer required,
- there is no longer a minimum reactive power capability range required,
- the undervoltage and overvoltage ride through envelopes are relaxed,
- there are no longer any requirements related to reactive power control modes.

The rationale for why the requirements for this category of generators should be relaxed is not clear. None of the listed relaxed requirement are expected to be significant cost drivers for solar power plants, not even at the low voltage level, and can therefore be seen as slowing down adoption of renewable power generation. In fact, connection requirements similar to those specified for larger systems described in Article 40 are common practice in other countries even for solar power connected at the low voltage level.

Recommendation

Instead of introducing a new category of solar power plants, with relaxed connection requirements compared to the existing rules, it would be better to add missing requirements to solar power plants connected at the low voltage level. Such requirements include active power control capability, and reactive power capability ranges and control modes.

3.4. Recommendations towards relay F81

High penetration of rooftop solar PV systems in the distribution grid can reduce the effectiveness of traditional under-frequency load shedding (UFLS) schemes. Traditionally, UFLS schemes aim to halt the decline in frequency in the event of unplanned loss of generation and restore the energy balance in the system by disconnecting portions of the load when the frequency falls below a certain threshold. This is done through preconfigured relays fitted to distribution feeders.

Typically, the load is shed in multiple stages as the frequency continues to decline until only a small portion of the load reserved for essential services remains online. UFLS schemes are considered a last resort to avoid blackouts [63]. For European networks, UFLS scheme recommendations provided by the European Network of Transmission System Operators for Electricity (ENTSO-E) can be shown in Figure 25. In each step of the UFLS scheme, no more than 10% of the load shall be disconnected.

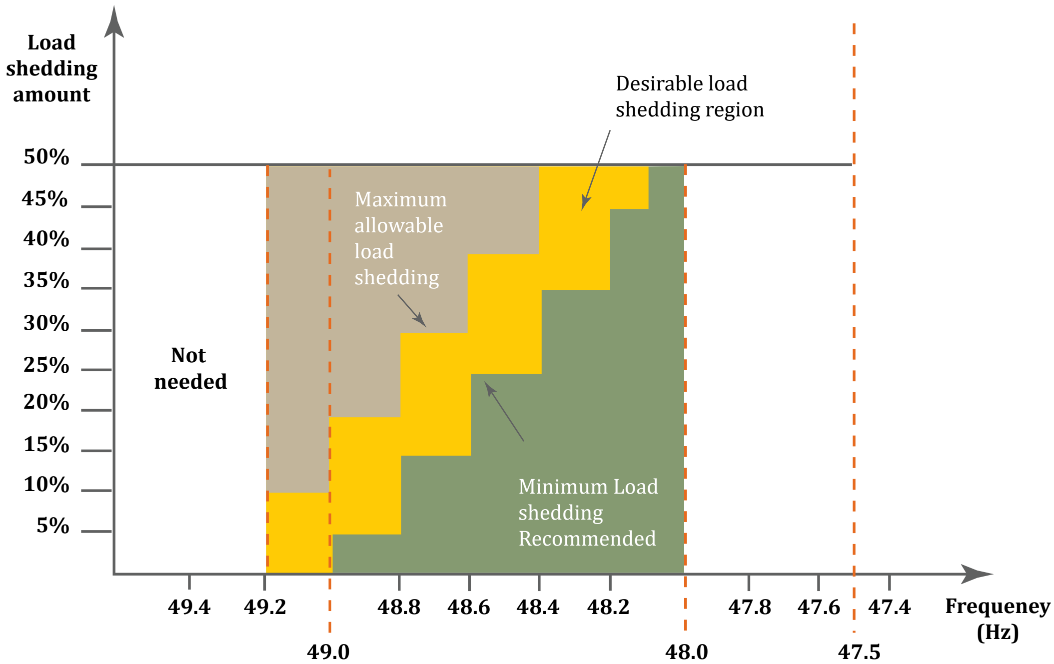

Figure 25. UFLS scheme recommendations provided by ENTSO-E.

Increased PV penetration reduces the net load during sunlight hours reducing therefore the available load to trip and thus the effectiveness of the UFLS scheme preconfigured within the relays. As more rooftop solar systems are connected to the distribution grid, the net load could further decrease until the load on the UFLS circuit goes into reverse flow. Traditional UFLS relays will disconnect the load regardless of the direction of the power flow. When a UFLS circuit is in reverse flow (i.e. the feeder becomes a generating feeder), the tripping of the relay will not only result in the unnecessary disconnection of customers, but will also accelerate the frequency decline across the network.

As an example, in South Australia at least one UFLS circuit was in reverse flow for 6% of the year in 2020 and during some periods, more than half of the UFLS circuits were in reverse flow with total UFLS load values reaching as low as 12 MW, as shown in Figure 26. At this moment, if a severe disturbance occurred that led to an underfrequency, the disconnection of customers would not support in stopping the frequency decline. [64]

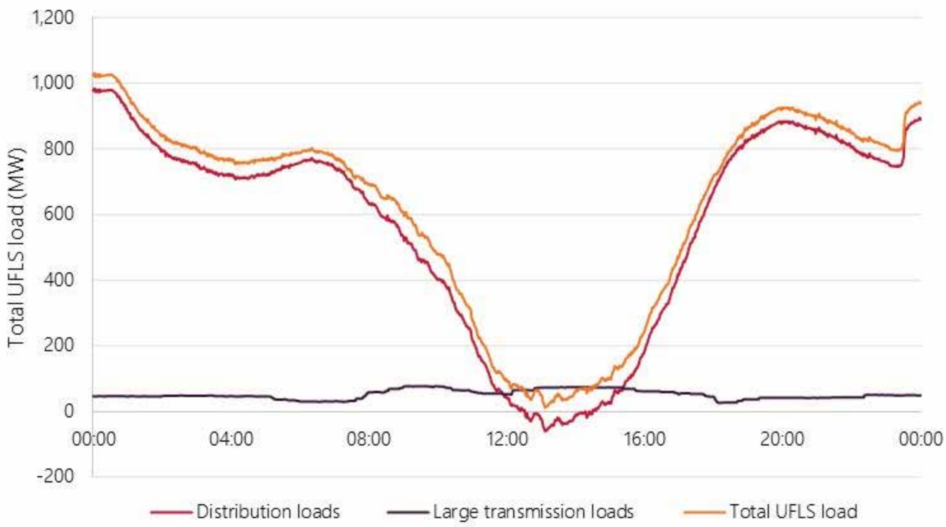

Figure 26. Minimum recorded UFLS load in South Australia in 2020 [65]

Actions can be taken to mitigate the effects of Distributed PV (DPV) on the UFLS capability. In Australia, AEMO has conducted comprehensive work on UFLS and the impact of distributed generation. In 2020 AEMO has defined a dynamic arming UFLS scheme and began its implementation in 2021. Dynamic arming of UFLS blocks would act to disarm frequency relays at feeders that are operating in reverse flows. This will fully mitigate the risk of the UFLS relays acting to exacerbate a frequency disturbance. To implement this scheme, directional relays must be used which take the current as an additional input to identify when the circuit is operating in reverse flow. [66]

To implement this method, the currently installed UFLS relays will need to be replaced by the TSO. It is international good practice to implement the method in a staged manner, targeting feeders with the largest amount of DPV installed first.

Traditional UFLS schemes preconfigured in relays are based on historical data. A representative day for every season is chosen and the setpoints of the UFLS scheme are chosen accordingly. In practice, the exact amount of load connected at the time of UFLS activation will be unknown. With the integration of more DPV in the system, the load pattern will change and the UFLS scheme setpoints must be changed accordingly. Traditional UFLS relays are not remote controllable and due to labor limitations, their configuration can be altered only a few times per year. Hence, it is recommended to install UFLS relays that can be remotely controlled. This would allow TSOs to dynamically assign UFLS setpoints to ensure the UFLS scheme meets the target load availability at all times.

Additionally, more loads can be added to UFLS circuits to restore the effectiveness of UFLS schemes. This can be done through adding transmission-level loads to the UFLS scheme which typically have lesser variability associated with DPV penetration, as exemplified in Figure 26. [63]

It is therefore recommended to limit or stop the installation of relay F81 (sheds load) on certain medium voltage feeders with significant RTS shares. Feeders with RTS capacity taking more than 50% of feeder capacity could be exempt from installing F81 function.

4. M&C implementation and operationalization strategy

The development of a technical national-wide solution for remote monitoring and control (M&C) is a continuous and gradual process. It is recommended to start based on international experience with a simple solution with minimum capabilities enabled and later gradually adjust the solution to better fit the needs of the system in Viet Nam, based on acquired learnings and stakeholder feedback.

Pilot Project (Phase 1)

A small pilot project at a selected location that has high RTS shares and with only a few connected DERs to the DERMS is a recommended first phase. The pilot will help identify potential challenges and improvements to the pilot's initial test DERMS version. The pilot project can be useful to:

- Assess different technology options (choice of communication protocols, communication media, device functionality, network architecture, ...).
- Demonstrate and quantify benefits of a DERMS solution in areas with high RTS shares, including benefits from forecasting and grid analytics functionalities.
- Identify challenges of the proposed solution, including challenges related to customer acceptance.
- Further identify gaps in existing technical standards, technology available in Viet Nam and Circulars.
- Better identify range of implementation costs of DERMS in Viet Nam.

Targeted Solution (Phase 2)

After an initial experience is gathered with the pilot DERMS, an improved DERMS solution can be applied to targeted areas with high RTS shares and that currently face grid issues (Phase 2). In Phase 2, the focus is to connect to the DERMS existing larger RTS systems (>500 kWp). This targeted DERMS solution will contribute to gather experience at a small scale and ideally from different areas/different PCs, to observe how the DERMS can be integrated considering different PC operation strategies.

Advanced Solution (Phase 3)

After gathering learnings from the small-scale solution applied in targeted areas, an advanced DERMS solution is recommended to be proposed (Phase 3) to be applied on a wider-scale and where needed. This advanced solution can be applied initially for RTS above 200 kWp that request connection to the system. The threshold of 200 kWp can be fine-tuned after a detailed cost assessment, which can be more accurately analysed based on initial findings from the costs observed in Phases 1 and 2.

Furthermore, as outlined in section 3.2, it must be identified whether DERMS and/or VPPs make more sense as an initial solution for remote monitoring and control of RTS in RTS hotspot areas in Viet Nam. For this, findings from increased visibility obtained via the initial DERMS pilot project (proposed as Phase 1) shall provide a better understanding of the current issues in an area with high RTS shares, and from the identification and quantification of issues, it will become clearer whether highly location specific services offered within a DERMS solution are necessary, whether services from VPPs (less location-specific) are sufficient instead or whether a combination of DERMS and VPPs is the most beneficial solution depending on the location. Costs and benefits of the VPP and DERMS solutions must be identified and compared, as well as required changes to market structure and regulations to enable each solution. A mixed approach can also be investigated, where VPPs are established as a first step and later assets can be gradually enabled within a DERMS platform. This approach would allow more time for EVN to gather confidence and experience with the technology and yields lower up-front costs compared to directly applying a DERMS solution. Many utilities begin the journey to DERMS with first establishing VPPs [67]. The establishment of VPPs in Viet Nam will depend on the advances in Viet Nam's plans to develop a competition-based generation, wholesale and retail market (aimed by 2023).

A roadmap with Phases 1 to 3 can be found in Figure 27. Tentative timeframes have been suggested for the completion of each phase. These must be revised and adjusted based on a more detailed breakdown of phases, tasks and milestones. Before each phase, an expert group should carefully analyse findings from previous phases, discuss the need and strategy for the next phase, and consult stakeholders. Furthermore, prior to implementation of Phases 2 and 3, the regulatory changes needed to allow such requirement for monitoring and control must have been identified and applied (including amendments to Circular 39/2015/TT-BCT), to have a basis for implementation.

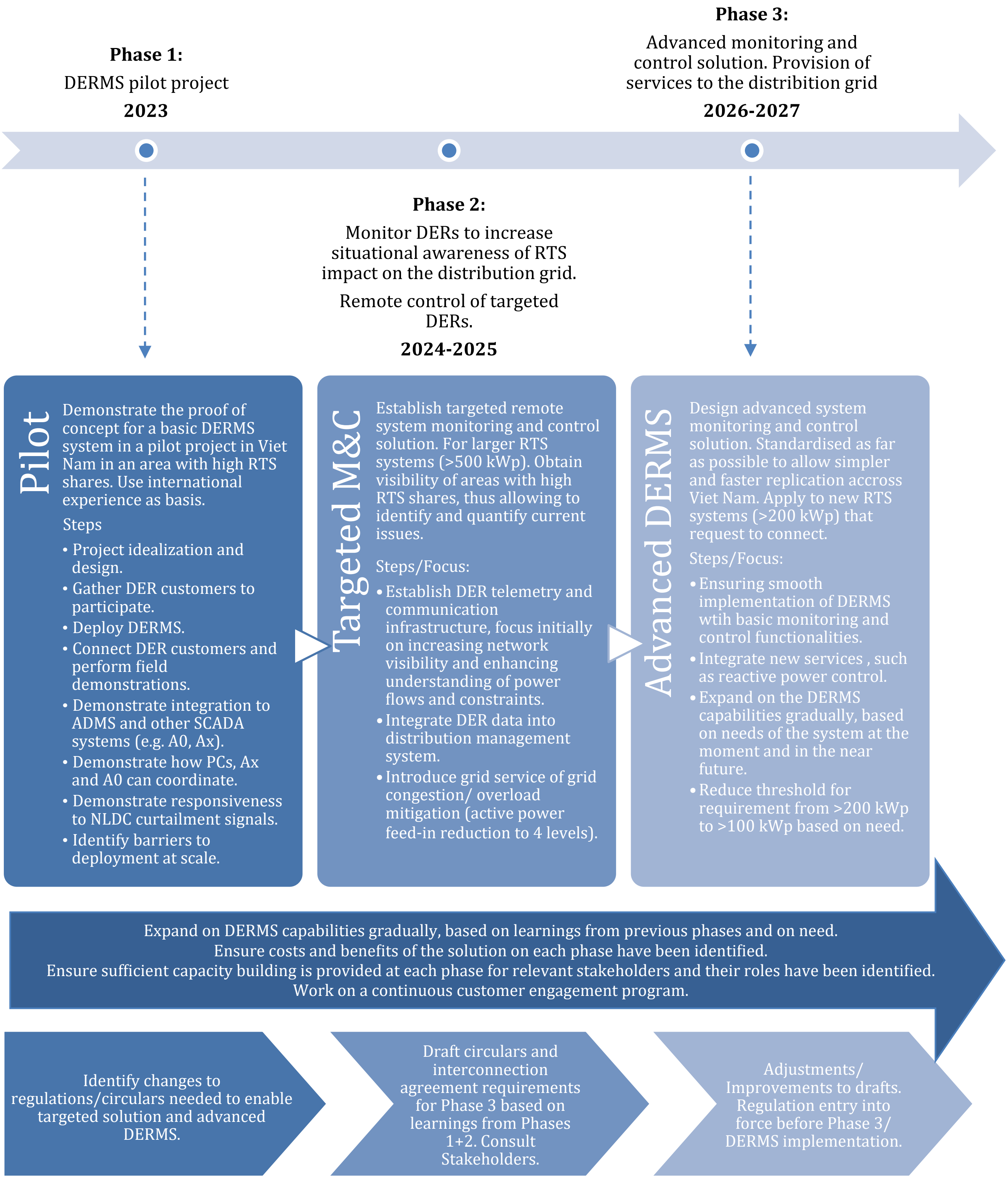

Figure 27. Roadmap to remote monitoring and control implementation and operationalization in Viet Nam.

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Annex

Annex 1

Smart controller: equipment specification sheet (at minimum):

Technical data	Specification
Communication	
Number of supported connections	Max 100 device connections
Telecontrol protocols (optional)	- IEC60870-5-101 Master/Slave - IEC60870-5-104 Master/Slave - Modbus Master/Slave (including RTU/TCP) - IEC61850 Client/Server - DNP3 - IEC62056-21 - SEL FastMessage
Interfaces	
Ethernet	2 x 10/100 fast ethernet port
RS232	2 x RS232 port
RS485	2 x RS485 2W/4W mode & terminal resistor configurable
Measure inputs	- 4 x Voltage channels, 0 ... 300VAC 1% - 4 x Current channels, 0 ... 3A 1% - 2 x General analog inputs, 0...30VDC
Digital inputs/outputs	- 4 x DI - 4 x DO
3G/4G Connection	
General features	- Multi-Band LTE-TDD/LTE-FDD/HSPA+/TD-SCDMA/EVDO - Dual-Band GSM/GPRS/EDGE 900/1800 - 2 x SIM interface, 1.8/3V

Specification	• LTE CAT4
	  - Uplink up to 50Mbps,
	  - Downlink up to 150Mbps
	• TD-SCDMA
	  - Uplink up to 128Kbps,
	  - Downlink up to 384Kbps
	• TD-HSDPA/HSUPA
	  - Uplink up to 2.2 Mbps,
	  - Downlink up to 2.8 Mbps

	• HSPA+ - Uplink up to 5.76 Mbps, - Downlink up to 42 Mbps • UMTS - Uplink/Downlink up to 384Kbps • EDGE Class - Uplink/Downlink up to 236.8Kbps • GPRS • Uplink/Downlink up to 85.6Kbps
Features	
CPU	Arm Cortex-A7, industrial CPU
Data storage	Flash 8G
Control function	
Power plant control function	- P, Q, V, Pf control - Frequency regulation function - Close loop control, open loop control - Start-up/Shut down solar power system/plant - Voltage monitoring function
Protocol converter	Support conversion between all telecontrol protocols
Power Supply	
Main power supply	85 ~ 305 VAC, 100 ~ 430 VDC
Internal electricity supply	12VDC battery pack
Ambient conditions during operation	
Ambient temperature	0 to 55 ºC
Permissible range for relative humidity (non-condensing)	5 to 95%, no condensation
Maximum operating altitude above MSL	2000m
Degree of protection	IP30
General Data	
Dimensions without base (W/H/D)	225/50/130 mm
Weight	(depending on the order)
Mounting type	DIN / panel mount
Material type	Aluminum sheet

Commercial and Industrial Rooftop Solar (CIRTS)

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