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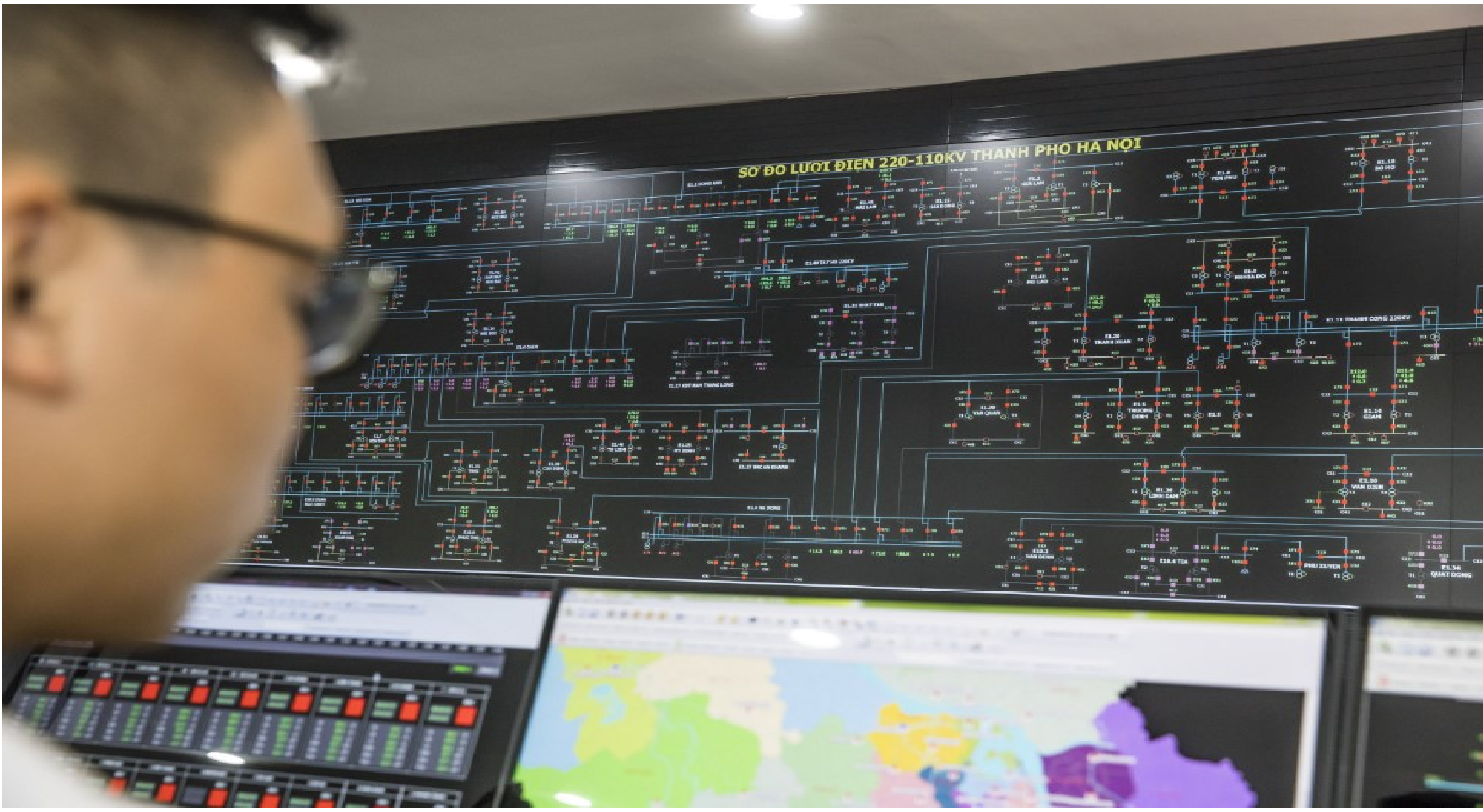

SGREEE-AA1: Promoting Implementation of Demand Response Programs in Vietnam

(Smart Grids for Renewable Energy and Energy Efficiency project)

Final Report

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On behalf of the
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Abbreviations

AEMO: Australian Energy Market Operator
AMI: Advanced Metering Infrastructure
AMP: Aggregator-Managed Portfolio
ARENA: Australian Renewable Energy Authority
ARP: Advancing Renewables Program
BIP: Base Interruptible Program
CAISO: California Independent System Operator
CBA: Cost-Benefit Analysis
CBL: Customer Baseline Load
CBP: Capacity Bidding Program
CIDCL: Hawaii C&I Direct Load Control
CIT: Corporate Income Tax
CLP: Curtailable Load Program
CMSC: Commission for the Management of State Capital at Enterprises
CPCS: "CPCS" or the "Consultant"
CPP: Critical Peak Pricing
CPUC: California Public Utilities Commission
DAS: Distribution Automation Systems
DBP: Demand Bidding
DEU: Designated Energy Users
DSM: Demand Side Management
DR: Demand Response
DRMS: Demand Response Management System
DRRC: Demand Response Research Center
DRQAT: Demand Response Quick Assessment T
EDRP: Emergency Demand Response Program
EE: Energy Efficiency
EEO: EE Obligations
EESD: Energy Efficiency and Renewable Energy Agency
EMA: Energy Market Authority
EM&V: Evaluation, and Measurement and Verification
ERAB: Energy Resource Aggregation Business
ERAV: Electricity Regulatory Authority of Viet Nam
EREA: Electricity & Renewable Energy Authority
ESCOs: Energy Services Companies
EVN: Electricity of Vietnam (state owned corporation)
EVNCPC: EVN Central Power Company
EVNHANOI: EVN Hanoi Power Company
EVNHCMC: EVN Ho chi Minh City Power Company
EVNNLDC: EVN National Load Dispatch Centre
EVNNPC: EVN Northern Power Company
EVNNPT : National Power Transmission Corporation
EVNSPC: EVN Southern Power Company
EVs: Electric Vehicles
EVO: Efficiency Valuation Organization
FERC: Federal Energy Regulatory Commission

FSL: Firm Service Level
GEJE: Great Eastern Japan Earthquake
GDP: Gross Domestic Product
GIS: Global Information System
GIZ: Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH
HCMC: Ho Chi Minh City
HEUC: Hourly Energy Uplift Charge
IL: Interruptible Load
IOT: Internet of Things
IPMVP: International Performance Measurement and Verification Protocol
IRP: Integrated Resources Plan
IOUs: Investor-Owned Utilities
ISO-RTO: Independent System Operator – Regional Transmission Organization
JEPX: Japan Electric Power Exchange
KEPCO: Korea Electric Power Corporation
KEU: Key Energy Users
KPX: Korea Power Exchange
LRF: Load Registered Facility
M&V: Measurement and Verification
MBI: Market-Based Instruments
METI: Ministry of Economy, Trade and Industry
MOF: **Ministry of Finance**
MOIT: Ministry of Industry and Trade, Vietnam
MOTIE: Ministry of Trade, Industry and Energy
NAPDR: National Action Plan on Demand Response
NEMS: National Electricity Market of Singapore
NLDC: National Load Dispatch Center
NPT: National Power Transmission Corporation
OCCTO: Organization for Cross-regional Coordination of Transmission Operators
OPA: Ontario Power Authority
OMS: Outage Management System
PC: Power Company (equivalent to distributor)
PDP: Power Development Plan
PM: Prime Minister
PNSEE: Programa Nacional para la Sustitución de Equipos Electrodomésticos
POPP: Peak to off-peak price
RCEE-NIRAS: Local Consulting Firm
RE: Renewable Energy
RERT: Reliability and Emergency Reserve Trader
RGGI: Regional Greenhouse Gas Initiative
RMSE: Root Mean Square Error
RRMSE: Relative Root Mean Squared Error
RTP: Real-Time Pricing
SAM: Supply Adjustment Mechanism
SAS: Substation Automation Solutions
SEEP: Super-Efficient Equipment Program
SGREEE: Smart Grids for Renewable and Energy Efficiency project
SLRP: Scheduled Load Reduction Program
SMP: System Marginal Price
SN: Short-Notice

SO: System Operator
TOU: Time of Use
USAID: United States Agency for International Development
VCGM: Vietnam Competitive Generation Market
VND: Vietnamese Dong (currency)
VWEM: Viet Nam wholesale electricity market
VPP: Virtual Power Plant

Acknowledgement and Disclaimer

The CPCS Team acknowledges and is thankful for the input and guidance of representatives from ERAV, GIZ, and RCEE-NIRAS.

Unless otherwise indicated, the views and opinions expressed in this report are those of the authors and do not in any way represent the official position of the Vietnamese Government or the German Government.

CPCS makes efforts to validate data obtained from third parties, but CPCS cannot warrant the accuracy of these data.

All translations from Vietnamese to English are non official translations, should any discrepancy arise from these translations, the original Vietnamese versions prevail.

EXECUTIVE SUMMARY

Executive Summary

Implementing Demand Response (DR) in Vietnam can bring multifaceted benefits to the country and provide economic, reliability, and system management benefits. While there have been successful DR pilot projects in Vietnam, a number of barriers remain to DR's implementation. This report is the Final Report of the assignment "Promoting Implementation of Demand Response Programs in Vietnam" carried out for GIZ. It is divided into three main parts. It begins with a review of the current DR regulatory and policy framework and institutional context. It follows with a review of international DR best practices, especially those that are most relevant to the Vietnam context. Finally, it outlines recommendations for DR program implementation for the short, medium, and long term.

Existing Regulatory Frameworks & Challenges for Demand Response Implementation

In 2019, electricity sales in Vietnam reached about 241 billion kWh, an increase of approximately 9.5% as compared to 2018. Even though this growth rate has been stable at 9.5-10% per year during 2010 - 2019, it is expected to drop slightly to 8% per year during 2021 – 2030. Installed capacity of the system was nearly 55 GW as of 2019 and is expected to be 138 GW by 2030 in order to guarantee power supply for socio-economic development.

Generation expansion is the main solution to meet power demand in long-term. However, in the short-term, Demand Side Management (DSM) and Demand Response (DR) in particular will play an essential role in maintaining reliability indicators. Other notable benefits of DR include system asset management, financial benefits for customers and lower power system production cost.

DR has been first introduced by Circular 23/2017/TT-BCT dated November 11, 2017 and then further institutionalized by Decision 279/QĐ-TTg dated March 8, 2018, Decision 17/QD-BCT dated January 28, 2019 and Decision 54/QD-DTDL dated June 12, 2019. Detailed guidance in term of process, monitoring and evaluation as well as institutional arrangement have been well described in these legal documents.
DR event implementation guidance is ready in term of technical and institutional however, financial supporting mechanisms are still missing. After years of pilot implementation, all Power Corporations (PCs) have faced challenges in encouraging customers to participate in DR events due to lack of financial incentives, i.e the financial benefits for customers who participate in DR events are not significant or clear. Without financial incentives, the level of participation of customers has decreased over time.

Direct compensation for customers participating in DR events has been applied during a pilot program in EVN-HCMC in 2015 from its Science and Technology Fund. However, this mechanism is mainly appropriate for short-term, pilot-type implementation. Expenses associated with DR event implementation are not eligible to be accounted as business expense so PCs are not able to pay direct compensation to customers neither deduct in their power bills. DR associated expense is not defined as an ancillary service in Vietnam as in other international power market.

A Time of Use (TOU) mechanism has been reflected in the existing tariff structure. For years, the TOU mechanism has contributed to shifting demand toward off-peak hours. However, the difference between peak and off-peak tariff is not significant enough to attract DR implementation. Additionally, as the power system evolves, the definition of peak hours needs to be more flexible in order to increase the efficiency of the TOU mechanism.

It is essential that all the above-mentioned barriers would be resolved in the future. Recommendations for policy improvement will be the starting point for policy makers in MOIT, ERAV to initiate intervention in the power sector to establish effective mechanism for DR implementation.

International Best Practices in Demand Response Program Implementation

Various international best practices can be examined to guide the implementation of Demand Response in Vietnam. Our study provided a survey of relevant proven international best practices related to successful DR program implementation, including summary descriptions of notable DR programs of interest to Viet Nam. The DR programs selected for review for this assignment were limited to successful examples, regional programs of note, or those that share similarities with DR programs recently piloted in Viet Nam. This survey was carried out in order to present the programmatic details of interest and to recommend further relevant improvements enabling implementation of the DR programs (including all sub-programs) outlined in Circular 23/2017/TT-BCT.

As such, our examination of best practices attempts to address the following questions: i) what are the most relevant jurisdictions in terms of programmatic offerings, climatic similarities, or other factors; ii) what characterizes their success; iii) what are the important lessons learned for Viet Nam from these jurisdictions. In addition to those three questions, our study of best practices also reviews the topics of program financing mechanisms, and measurement and verification (M&V) methodologies, including for baseline calculations that are in use in these jurisdictions.

Summary description of DR programs from the following selected jurisdictions are presented: South Korea, Japan, Singapore, Australia, and the US state of California. It should be noted that this study aimed for the balance between a simple international survey of DR programs, and a deep analysis of those DR programs that have some relation to Viet Nam's programs and conditions. This approach was chosen because a survey would only be useful before the implementation of any pilot DR programs, while a case study would be more appropriate once key DR program elements have been identified for Viet Nam, allowing the case study to further cover each program element of interest in depth.

We review the questions of relevancy, DR programmatic offerings, and success factors, as well as summarize the financing mechanisms, measurement and verification, as well as the baseline calculation methodologies in use. The topic of baseline calculations and M&V methodologies are not yet needed until specific program details have been finalized by ERAV. Nevertheless, several of these methods can be helpful and useful for Viet Nam in designing its own M&V system and developing the general principles that can guide the M&V and baseline process going forward.

Of the program details described, Japan's and Korea's use of the "Negawatt" markets – specifically their use of a public trading exchange for the wholesale selling and buying of electricity resources – received significant interests from stakeholders. In fact, all of the jurisdictions presented here use some forms of a trading exchange to manage the flow of electricity resources through their system. A related area of interest to stakeholders is the use of aggregators to reduce the administration burden for the implementing agencies or utilities. Of note, California also uses aggregators to manage residential customers, the state's utilities also have aggressively installed "smart meters" for all customer sectors, which has facilitated customer participation in DR programs by automating the DR process.

The jurisdictions studied operate in markets where DR providers can compete. All of them allow and rely on the use of aggregators in the wholesale power market. In these jurisdictions, aggregators pool many different loads of varying characteristics and provide backup for individual loads as part of the pooling activity, increasing the overall reliability and reducing risk for individual participants. They create one "pool" of aggregated controllable load, made up of many smaller customer loads, and sell this as a single resource. A DR aggregator can be part of different entities or a third-party entity, depending the on the state of their market. Details on aggregators, their business models, development stages, and financing mechanisms are included, along with details on how each of the jurisdiction finance their DR programs.

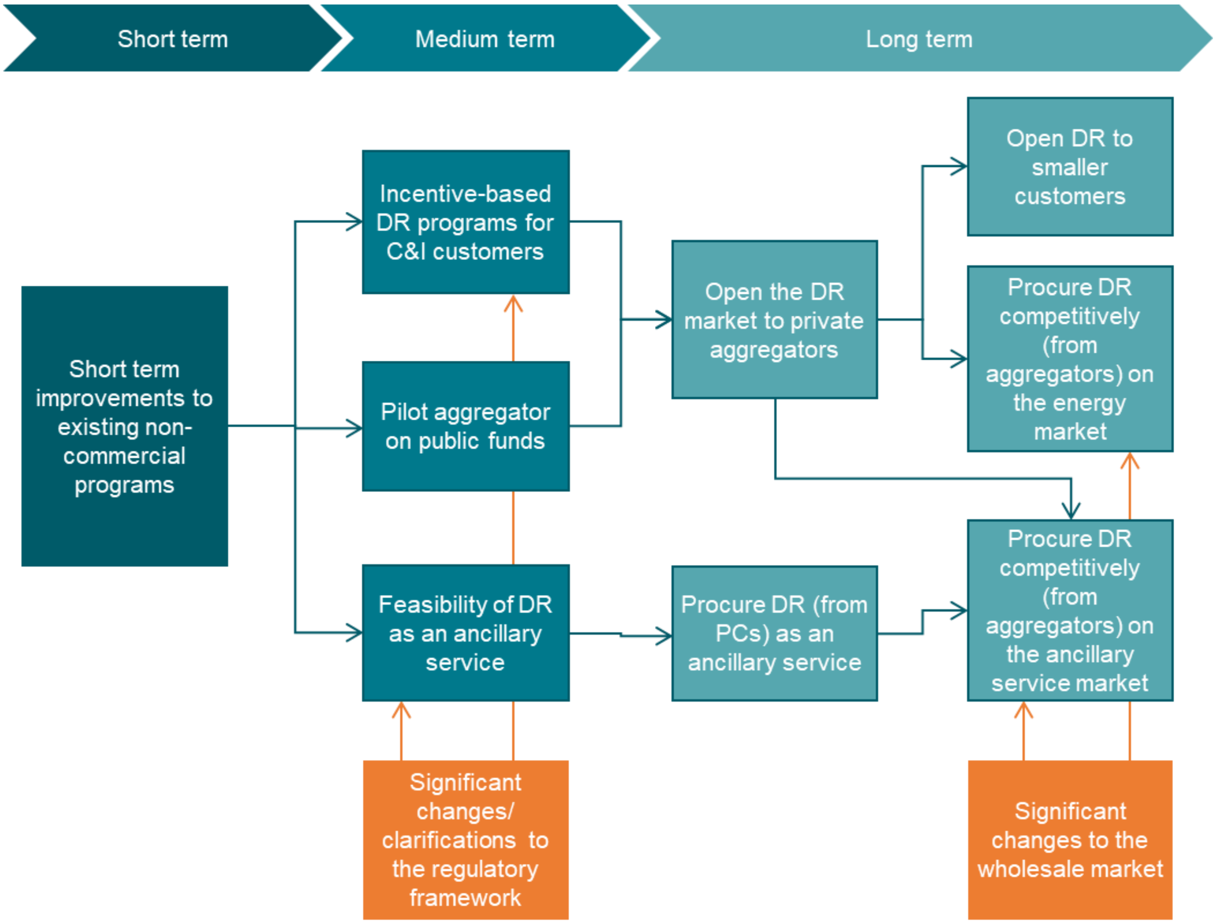
Both a trading exchange and the use of aggregators will require further development of the Vietnamese DR market, and are the logical next steps for Viet Nam's DR program activities and focus.

The path to Demand Response Deployment in Vietnam

Our work laid out several long-term options for the deployment of DR in Vietnam. At this stage, there is not enough evidence to determine which option(s) is the best in the long term. All options could be implemented in parallel, or they could be staged through time, or it will slowly become clear that one of them is the best bet to achieve Vietnam's load reduction targets.

The two charts below provide an overview of the options that we have explored in our study, starting with **Incentive-based DR** (**Program 1 from Circular 23)**. For this program, in the short term, several improvements must be brought to the existing non-commercial DR programs. In subsequent stages, three options can be envisaged: switch from non-commercial to commercial DR programs within the existing PC-administered framework ; prepare the terrain for the aggregator model, by running a pilot aggregator program on public funds ; and examine the feasibility of on-selling DR as an ancillary service to the system operator. Significant changes or clarifications need to be brought to the regulatory framework to make this possible.

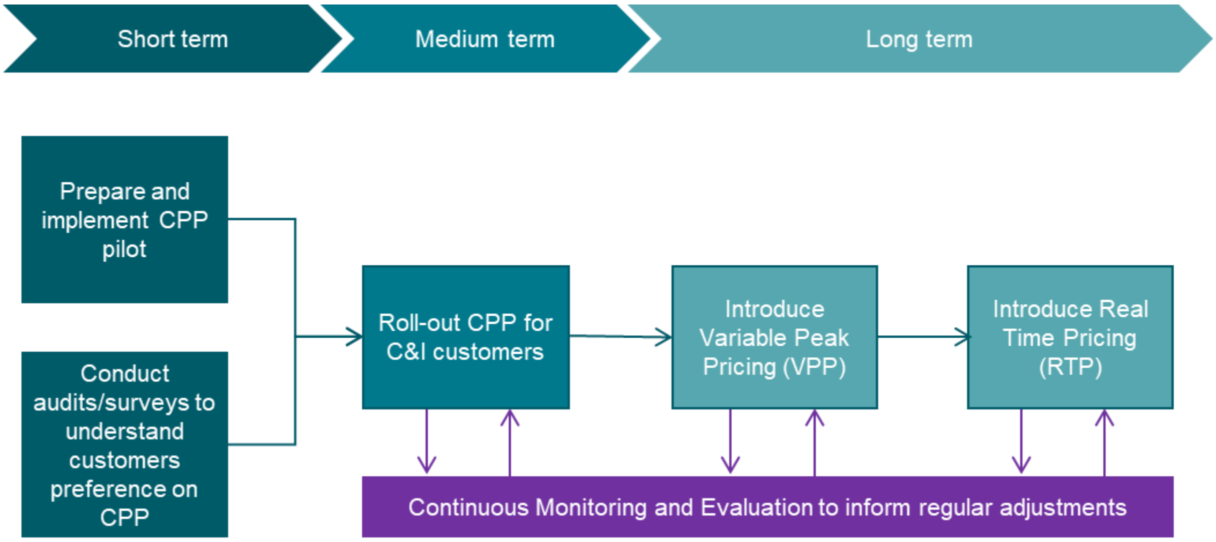
The path to DR deployment: several long-term options for Incentive-based DR (Program 1 from Circular 23)



In the long term, assuming that the development of the VWEM continues in parallel, this would pave the way for private aggregators trading DR on either the energy market, or on a (yet to be created) competitive capacity or ancillary service market. As aggregators get up to speed, they could also start targeting smaller customers. It is too early at this stage to recommend one long-term option over the others. We suggest that the Vietnamese authorities keep all these options on the table until enough information becomes available to select one (or several) of them and dismiss the others.

As regards the **peak load electricity tariff program (Sub-program 2.2 from Circular 23)**, the path is more straightforward. Regulatory obstacles are much less important: the possibility of introducing peak time tariff is already mentioned in PM Decision 28/2014/QD-TTg *Regulations on structure of electricity retail tariff*. The first step towards the deployment of critical peak pricing (CPP) is to prepare and implement a pilot program.

The path to DR deployment: peak load electricity tariff (Sub-Program 2.2 from Circular 23)



After the pilot, CPP could progressively be extended to a larger number of C&I customers. In the longer term, keeping pace with the evolution of the VWEM, variable peak pricing (VPP) and ultimately real-time peak pricing (RTP) could be introduced.

In addition to the necessary adjustments to the regulatory framework, a range of cross-cutting measures are required to support the deployment of these various options:

- Continuous monitoring and periodic assessment of technological readiness
- Preparation of the switch from manual / local DR to automated / remotely controlled DR (Direct Load Control program)
- Building the capacity of EVN and PCs to implement DR
- Empower energy managers for commercial and industrial facilities with demand response training

To pave the way for future developments, we recommend the following 8-point Action Plan for the short term.

N°	Title	Pertains to	Lead
1	Continue efforts to encourage behavior change in C&I customers	Non-commercial DR (Program 1)	PCs
2	Build the capacity of PCs, EVN, and C&I customers	Non-commercial DR (Program 1)	MOIT
3	Adopt a regional approach to triggering DR events	Non-commercial DR (Program 1)	EVN
4	Conduct Monitoring and Evaluation (M&E) of existing programs, including Cost-Benefit Analysis (CBA)	Non-commercial DR (Program 1)	MOIT
5	Conduct studies/surveys to understand customers preferences	Cross-cutting	MOIT
6	Design a pilot Critical Peak Pricing program	Peak load electricity tariff program (Sub-program 2.2)	MOIT

INTRODUCTION TO THE FINAL REPORT

Introduction

Authority for the Assignment

This Working Paper has been prepared under the authority of the service contract signed between the Deutsche Gesellsschaft fur Internationale Zusammenarbeit ("GIZ") and CPCS Transcom Ltd. ("CPCS" or the "Consultant") on November 27, 2019 to provide consultancy services for "Promoting Implementation of Demand Response Programs in Vietnam"

Assignment Objective and Scope

The stated objective of the Consultant's assignment (the "Assignment") is to:

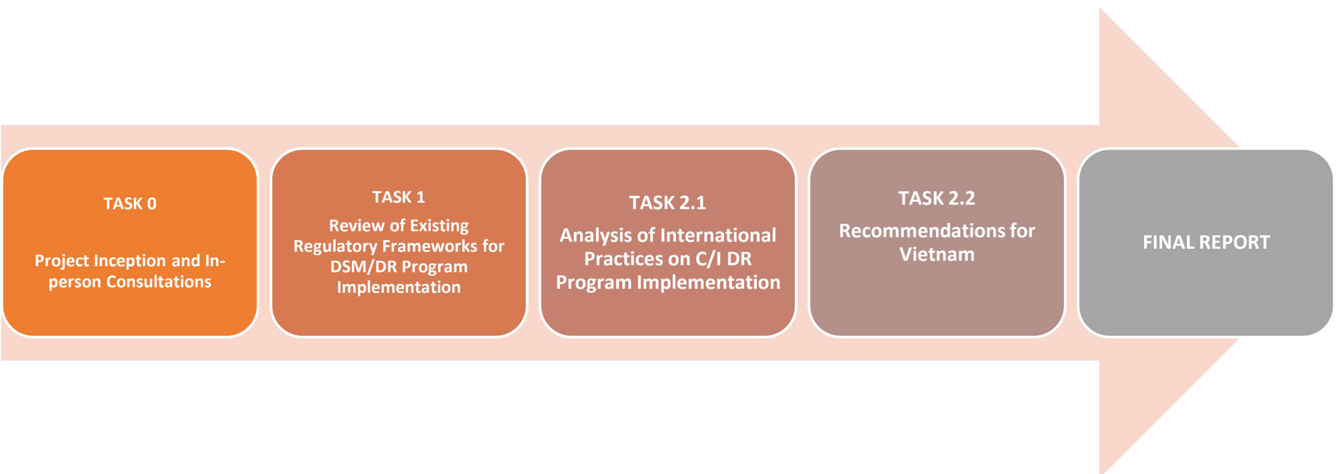
Provide advisory services in connection with the implementation of voluntary demand response programs in the commercial and industrial sectors.

The Assignment focuses on the following DR programs:
- Curtailable Load Program – CLP
- Emergency Demand Response Program – EDRP
- Real-time peak-load electricity tariff program

The CPCS Team has conducted a review of the current demand response (DR) regulatory and policy framework, examined the institutional context, and conducted stakeholder consultations to assess the present state of implementation of DR. This has been followed by a review of international DR best practices, especially those that are most relevant to the Vietnam context. Finally, the CPCS Team has contrasted those international models and experience with current approaches in Vietnam and developed recommendations.

Purpose of this Final Report

This report is the final report of the assignment, and compiles the working papers from tasks 1, 2.1, and 2.2, in addition to a methodology to carry out a cost-benefit analysis (CBA).



Assignment Context

Demand response is broadly defined as "changes in electric use by end-use customers from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."[1]

Vietnam has, for the past 13 years, been gradually experimenting with demand response. Without going into great detail in this introductory part on the various legislative and regulatory instruments that have been put in place, the following provides a brief timeline on the state of demand response implementation.

- From 2007-2015, pursuant to the Minister of Industry Decision 2447/QD-BCN dated 17/7/2007 on Approving the National Program for Power Demand-side Management, EVN implemented DR-related initiatives including customer education and equipment audits and upgrades at the customer end.[2]
- In 2015, in line with the Prime Minister's Decision 1670 / QD-TTg dated November 8, 2012, approving the Smart Grid Development Project in Vietnam, and Decision 2324/QD-BCD of March 19, 2014 by the Steering Committee of the Smart Grid Development Program[3], EVNHCM rolled out a pilot DR program in Ho Chi Minh City (HCMC) for large commercial and industrial customers.
- Following the EVN-HCMC pilot and the learnings it provided, on November 2017, Circular 23/2017/TT-BCT was issued by the Ministry of Industry and Trade (MoIT) on Prescribing Contents and Processes for Implementation of Load Adjustment Programs ("Circular 23"). Circular 23 is a central document for this Assignment.
- In 2019, following the Prime Minister's Decision 279/2018/QD-TTg of March 8, 2018 on the National Program on DSM period 2018-2020 with a vision for 2030, EVN organized 10 voluntary, non-commercial DR events.

The Ministry of Industry and Trade (MOIT) is officially tasked to lead national demand-side initiatives, including DR.[4]

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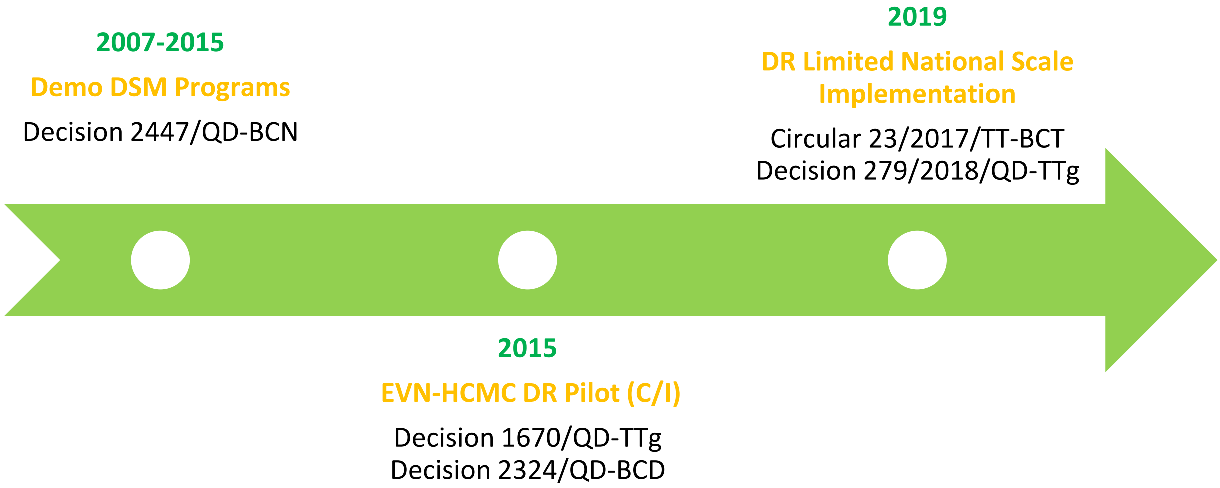
[1] Source: US Federal Energy Regulatory Commission.

[2] Direct Load Control (DLC) programs, other load research, time of use meter, and reactive power compensation.

[3] Approving the 2014 work plan, including the development of incentive mechanisms for customers to pilot the program at EVN-HCMC.

[4] In accordance with the Prime Minister's Decision 279/2018/QD-TTg.

Figure 1-1: Timeline DR Implementation in Vietnam and Associated Legislation



As described above, demand response has been carefully examined and gradually phased in since 2006. More recently, because the country will face potential supply shortages in the coming years, Vietnam has undertaken a national-scale demand response rollout to help maintain supply balance, quality and reliability of power services. Circular 23 explores a wide range of DR programming, including dispatchable incentive-based programs, non-dispatchable time-based programs, non-commercial DR programs, and voluntary DR programs.

This Assignment will focus on discussing how to best implement the following three programs: [5]

- The Curtailable Load program;
- The Emergency Demand Response program; and
- The Real-time Peak Load Electricity-tariff program.

The programs identified in Circular 23 are at various stages of implementation, as summarized in the table below.

[5] A more complete description is provided later in this paper.

Table 1-1: Implementation Status of DR Programs

Program	Status of Implementation
Dispatchable Incentive-based DR Programs	
Curtailable Load Program - CLP (voluntary program targeted at the industrial and commercial customers that have flexible production lines with consumption ranging from low levels to high levels). The CLP is an economic based program and is designed to drive efficiency, and reduce the cost of production for the marginal unit of electricity.	Pilot 2019 Scaled DR Planned (beyond 2020)
Emergency Demand Response Program - EDRP (voluntary program targeted at the industrial and commercial customers that have flexible production lines with a wide range of consumption levels, and are able to change or reduce electricity demand quickly). The EDRP is designed to ensure power system reliability. Demand response is deployed in the event that the power system is overloaded.	Pilot 2019 Scaled DR Planned (beyond 2020)
Non-dispatchable Time-based DR Programs	
A two-tiered electricity tariff program (demand charge and energy charge; targeted at customers who have already been on Time of Use tariff). There is no direct financial incentive mechanism for this program. Customers need to actively decide to adjust or change their demand to respond to price signals, especially within the peak time period to reduce electricity billing.	Not in Scope[6]
Real-time peak-load electricity tariff program (voluntary program targeted at industrial and commercial customers). The tariff includes TOU tariff and special tariff for the peak time periods(The peak time periods are announced on a case-by-case/time-to-time by authorized operators.).	Planned (beyond 2020)
Non-commercial DR Programs	
In this model, there is no financial incentive. The reward can be a "payment" in the form of preferential treatment if load curtailment is implemented as a last resort measure to maintain integrity of the power system.	2019 Scaled DR
Voluntary DR Programs	
As envisaged in Circular 23, in this model, there is no financial incentive. The reward may be in the form of goodwill as the customer is seen as contributing to social good. It is unclear whether and how a corporation can incorporate such goodwill in its accounting system.	Not in Scope

Structure of the Final Report

This final report is divided into three main sections, following the terms of reference. Part I is a review of existing regulatory frameworks for DR program implementation, where we review the current policies and regulations related to demand response, and identify barriers relating to DR program implemetation. Part II is a review of relevant international best practices in DR program implementation which examines the DR ladscapes and financial incentive mechanisms in South Korea, California, Japan, Singapore and Australia. Finally, Part III provides recommendations for DR program implementation, presenting recommendations for the short, medium, and long term.

[6] "Not in scope" means that neither the pilot nor the 2019 scaled DR initiative, or this current Assignment has looked into or will look into the implementation of this type of DR program.

Part I: Review of existing regulatory frameworks for DR program implementation

Part II: Relevant international best practices in DR program implementation

Part III: Recommendations for DR program implementation

PART I

REVIEW OF EXISTING REGULATORY FRAMEWORKS FOR DR PROGRAM IMPLEMENTATION

Chapter 01

Introduction

1 Introduction

The purpose of Part I: Review of existing regulatory frameworks is to the review the existing demand response legal and regulatory frameworks, and existing implementation and near-term programming. Importantly, this section identifies barriers to enable DR implementation, and reviews the recently issued Decision 54 on the Implementation of the Procedures for Implementing DR. Decision 54 was issued by ERAV as a guideline to PCs when they implement DR events, although it does not specify incentives for DR. This Working Paper will identify obstacles and/or constraints, to DR national roll out.

This section intends to answer the following questions:

1. Is DR an appropriate answer to the challenges facing Vietnam's power sector?
2. Is there a clear policy, strategy and implementation program regarding DR?
3. Is the existing institutional and regulatory framework appropriate to implement the program?
4. Is the feedback from the 2019 rollout encouraging as regards further implementation of DR?
5. What are the remaining barriers to successful implementation of DR?

Chapter

02

The Need for Demand Response: Demand, Supply and Tariffs

2 The Need for Demand Response: Demand, Supply and Tariffs

In this chapter, we look at the drivers behind demand response adoption and the objectives set by the Vietnamese government. We then reposition demand-side policies in the context of tariff setting.

2.1 Value of Demand Response

Demand responsiveness is not a panacea to resolve power supply and reliability but it is credited with many positives from the electrical system perspective, from the customer's end, and society more broadly. The theory behind DR features the following benefits:

System asset management benefits: DR can lower capacity requirements and allow utilities to avoid the expense of new power generating capacity. As power prices match production costs more closely, the savings can be passed onto retail customers.

Reliability benefits: DR can lower the probability and impacts of forced outages.

Customer benefits: Customers can adjust their demand, which results in a lower bill or incentive payments.

Economic benefits: With reduced demand during peak periods, the need to dispatch higher-cost power plants is reduced. This results in lower wholesale electricity production costs and prices.

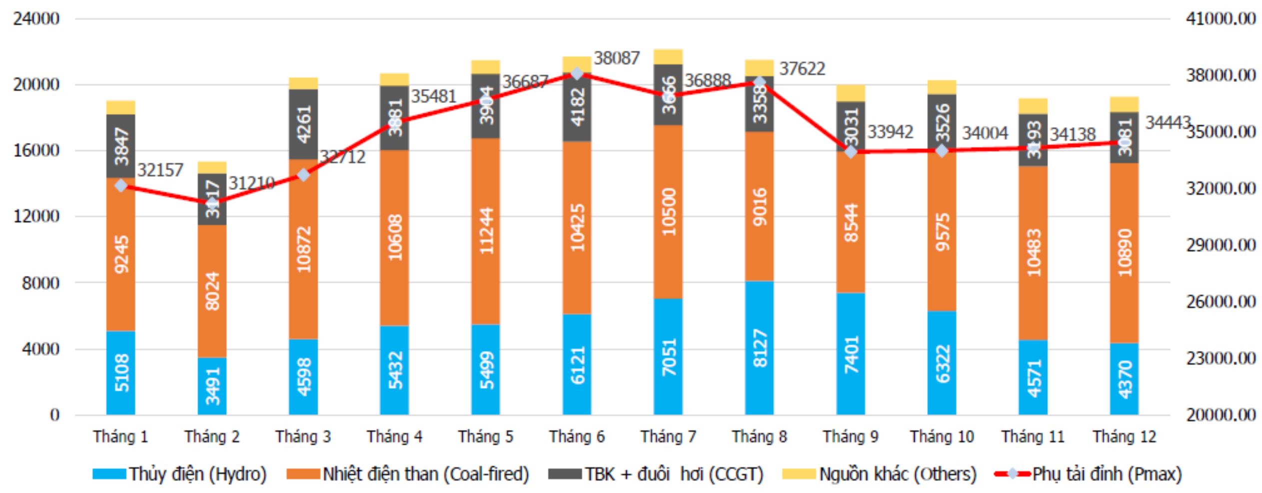
Other benefits include potential environmental benefits from reduced power plant operation, flexible customer usage options, and increased flexibility to respond to system contingencies. While these cited secondary benefits are not easily quantifiable, the cost avoided when a more expensive power plant is not dispatched can be estimated from the avoided variable operating costs associated with the power plant.

2.2 Drivers: Demand and Supply

The reasons behind the momentum for demand response in Vietnam is largely driven by demand and supply fundamentals and reliability considerations.

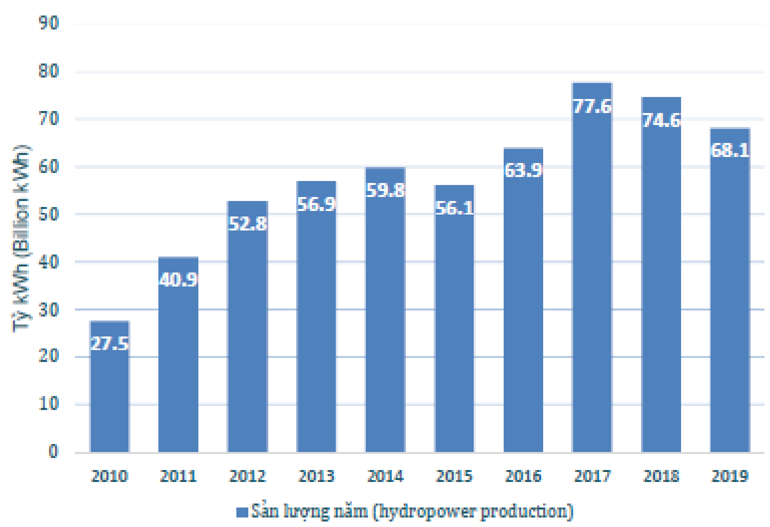
In 2019, electricity sales reached about 241 billion kWh (including power production sold to Cambodia), an increase of approximately 9.5% as compared to 2018. Vietnamese baseload generation is hydro based, which makes it prone to meteorological fluctuations, and puts upward pressure on prices when water levels are lower than required. Economic demand response may be one way to hedge against weather related variations.

Figure 2-1: Monthly Power Generation and Peak Demand in 2019



Source: EVNNLDC, 2019 Vietnam Power System and Power Market Operation

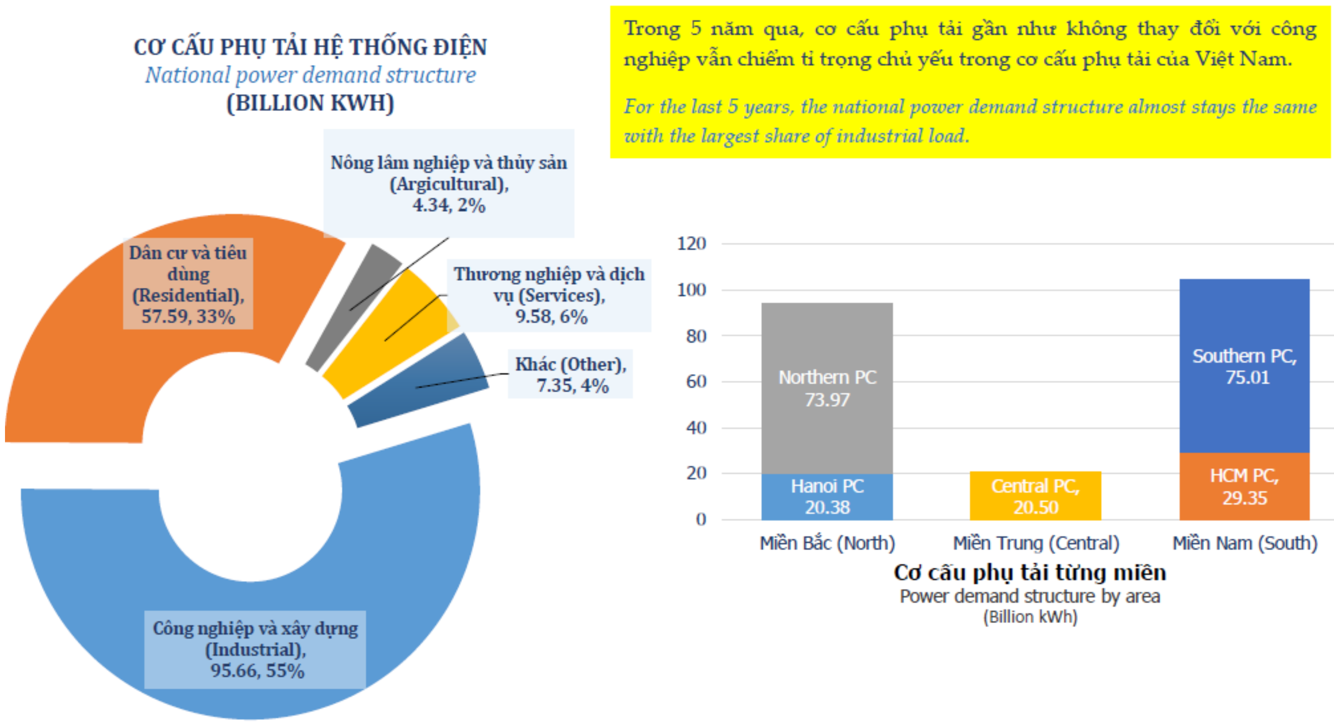
Figure 2-2: Hydropower Production, 2010-2019



Source: EVNNLDC, 2019 Vietnam Power System and Power Market Operation

In 2019, the industrial sector absorbed 55% of total demand, while the residential sector sat at about 33%, a split that has according to EVNNLDC remained stable over the past five years.

Figure 2-3: 2019 Demand by Sector and Service Territory



Source: EVNNLDC, 2019 Vietnam Power System and Power Market Operation

As highlighted in a recent interview of EVN's Head of Business Board, by Mr. Nguyen Quoc Dung, reliability considerations are top of mind, and a major driver for the adoption of demand response:

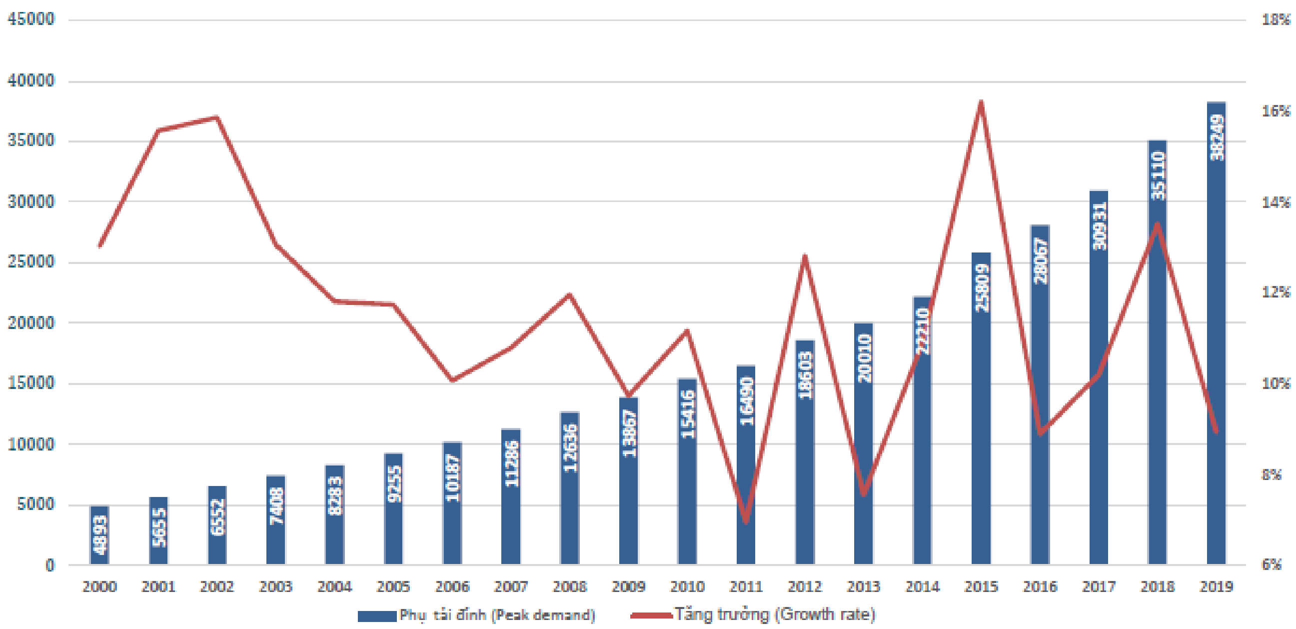
> *"Currently, Vietnam's power system no longer has back-up sources while the growth rate from commercial customers has remained a very high rate of about 10% per year. During peak hours, demand for power consumption increases, without DR programs, the power system may face an overload, which would mean that the system would no longer be able to supply power to a large number of customers. If DR is not implemented, we will have to make a huge investment in power source and grid to be able to meet the maximum capacity level of the power system. Such a high level of capacity can last only for 10 to 15 minutes, but its required investment capital is too large, leading to very high unit costs for power production, putting tension on selling price, directly affecting power users.[7]"*

The number show that demand peaked at 38,249 MW in 2019, an increase of about 9% compared to 2018, and the overall picture is striking with less than 5,000 MW in 2000 to this 2019 peak above 38,000 MW, an almost linear growth, with year over year increases of about 15%. Projection until 2030, show that Vietnam will need to add 6,000-7,000 MW of capacity annually to meet the country's needs.

[7] https://en.evn.com.vn/d6/news/Why-demand-response-program-must-be-implemented-in-Vietnam-66-163-1535.aspx, consulted February 2020 (note: with slight modifications related to translation)

While authorities have in able in the past 20 years to keep up with growing demand thanks to large investments in the sector, projected capital needs are, according to the International Finance Corporation[8], in the range of US$148 billion by 2030. In spite of the opening of the generation market since (2012 VCGM), wholesale prices have been too low to encourage deep private investment sector.[9] Another solution to ease pressures on supply are imports as Vietnam has exhausted home-grown generation resources. However, additional capacity through imports is also limited by interconnection capabilities. Demand-side management measures in this context, including DR appear necessary.

Figure 2-4: Demand Growth, 2000-2019



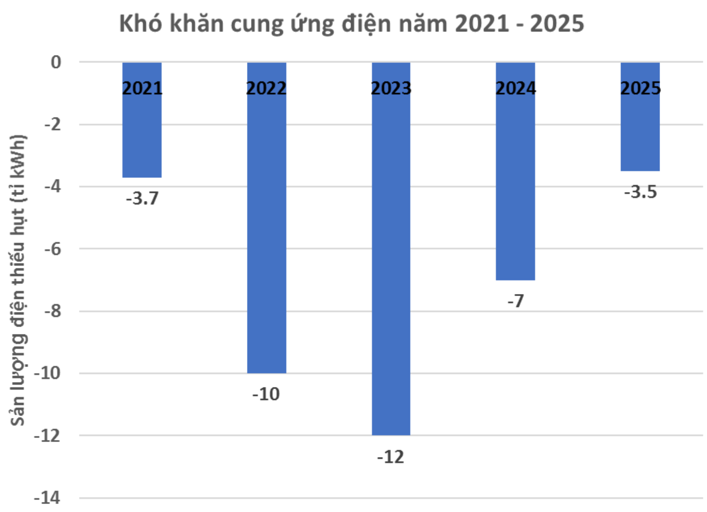
Source: EVNNLDC, 2019 Vietnam Power System and Power Market Operation

According to EVN, the prospect for shortages is real and projections in the high risk scenario looking at the following shortages

- **Year 2021 – 2025:**
    - Power shortage from 3.5 billion -12 billion kWh
- **Year 2026 – 2030:**
    - 2026 -2027: demand satisfied
    - 2028 -2030: shortage from 1.5 billion to 12 billion kWh

[8] https://www.vir.com.vn/vietnam-seeks-investment-in-energy-market-66737.html, consulted February 2020

[9] https://en.evn.com.vn/d6/news/WB-expert-Electricity-tariff-is-low-Vietnam-is-among-the-top-electricity-consumption-countries-in-East-Asia-66-163-821.aspx, consulted February 2020



Source: EVN

With a projected load growth factor of 3-4% in the 2021-2030 period, to ease pressures on the system and help balance supply and demand, DR targets until the 2030 horizon include a reduction of at least 30% of the overall peak load, corresponding to at least 90 MW by 2020, 300 MW by 2025 and 600 MW by 2030.[10]

2.3 Theoretical Considerations on Tariffs and Cost Allocation

In this section we will focus on rates. In the preceding section we mentioned that private investments in generation have not been as dynamic as hoped for since the introduction of a generation market in 2012. One of the reasons cited for the lack of investment in capacity by private entities, is the low level of tariffs.

2.3.1 Tariffs

Electricity tariffs are designed to ensure the financial sustainability of the sector and the efficient use of electricity.

Financial Sustainability: Tariffs are the mechanism by which utilities collect revenues from customers. In the regulatory world, utilities and regulators strive to reach tariffs that are "fair, just and reasonable". Tariffs should be set such that they balance the interests of ratepayers with the interests of the utility as a going-concern. The question of whether tariffs are fair, just and reasonable is at the heart of tariff hearings, and case law and an accepted set of principles is relied upon by regulators to make that determination.

From the utility's perspective, there are two essential elements in determining fair, just and reasonable tariffs: the recovery of costs that are prudently incurred, and the right to earn a reasonable return on investment. This is necessary to ensure that utilities remain financially viable and can attract the financing necessary for future investments. Costs must be recovered for financial sustainability.

[10] Decision 175/QD-BCT dated 28/01/2019 on Approving the Implementation Plan and Roadmap for the DR Program

A 2016 World bank report[11] highlighted issues related to EVN'S financial sustainability, singling out the **inadequacy of retail tariffs as a major challenge for EVN and the vibrancy of the industry.**

Without expanding on this, we will recall the key financial attributes of a good tariff structure, as enumerated by James Bonbright[12], and they include:

1. Tariffs should effectively yield total revenue requirements under the fair return standard.
2. Tariffs should provide revenue stability from year to year.
3. Tariffs should apportion the total cost of service fairly among different consumers.

Another key attribute Bonbright cites is that tariffs should promote efficiency, discouraging wasteful use of energy while promoting all justified types and amounts of use." We address efficiency in the following paragraph.

Efficient use of electricity: Tariffs that are based on the marginal cost will provide a price signal to consumers about the economic costs of supplying electricity. In the absence of TOU tariffs, the price signal reflects the average cost of electricity, in spite of the fact that in reality peak electricity and off-peak electricity are different products, with different production costs.

TOU tariffs provide time differentiated price that provide more efficient price signals that allow consumers to make decisions about how they use electricity more efficiently. There is an incentive to use less power when the cost of production is high. Demand response programs provide a more efficient price signal, ideally by linking the price in the highest demand period to the cost that can be avoided by curtailing consumption; thereby shifting consumption from the system peak which increases economic efficiency.

Public policy enabler: While the redistribution of revenues is not a standard purpose of regulated tariffs, they can be designed as a welfare support tool for residential consumers or they can support specific sectors, for example to promote industrial development.

In this case, tariffs help implement public policy. It is not clear whether this is the case in Vietnam. We will not discuss the pros and cons of using electricity pricing as a mechanism to channel public policies, but note that in a competitive electricity market they can give rise to controversy.

2.3.2 Cost Allocation

As mentioned above, tariff should apportion the total cost of service fairly among different users. To reach "fair, just and reasonable" rates, utilities apportion total

[11] World Bank, A Financial Recovery Plan for Vietnam Electricity (EVN), With Implications for Vietnam's Power Sector, April 2016

[12] Bonbright, James C, Principles of Public Utility Rates, Columbia University Press, New York NY, 1961,

costs they incur in what is known as a class cost of service study to the various customer classes. To appropriately functionalize, classify and allocate costs the cost causality principle is applied, namely at each of the step of the cost allocation model, the question asked is what caused the cost.

The cost allocation model determines:

- → Whether each class of customers is providing the utility with a reasonable level of revenue necessary to cover the investments and costs of providing service to that class.
- → Class revenue requirement/responsibility of each class for its equitable share of the utility's total annual cost of providing service within a given jurisdiction.
    - Creates pricing signals that encourage efficient use of system capacity.
    - Avoids undue price discrimination among classes of customers.

In Vietnam, without going through the cost allocation model in use, we understand that industrial customers pay the lowest tariffs.

2.4 Current Tariffs in Vietnam

The Ministry of Industry and Trade and ERAV in particular is accountable for electricity tariff setting as defined in Prime Minister's Decision No.: 28/2014/QD-TTg of April 2014 on Regulations on Structure of Electricity Retail Tariff. MOIT/ERAV is also responsible for fulfilling particular requests as highlighted in the statements below. In particular, Article 5, paragraph 1 of this Decision states:

> ***Article 5. Implementing Organization***
>
> 1. *The Ministry of Industry and Trade shall:*
>   *a)* ***Regulate and guide the implementation of electricity retail price for groups of electricity customers and the electricity price for the electricity retailing units;***
>   *b) Study the formulation and request the Prime Minister to consider and approve:*
>   *- Mechanism of electricity price of 02 components including the power price and electricity price for groups of electricity groups when the technical conditions are favorable;*
>   *-* ***Incentive mechanism of electricity price for pilot application for customers participating in the program of electricity demand management;***
>   ***[Emphasis added]***

This Decision identifies four customer classes grouped as: manufacturing, administrative, business and residential. Based on EVN data, the table below shows the applicable tariffs for the various end-users at different voltage levels and times of use. The table also highlights the fact that the lowest off-peak tariff and lowest peak tariffs correspond to usage by industrial customers.

Based on current information we have, the cost causality of tariffs in Vietnam is not clear, namely we are not certain that the lowest peak tariffs paid by industrial customers correspond to their contribution to EVN's peak cost. The question becomes how much incentive is necessary to move the position of industrial players to take part in demand response initiatives since their rates are already low. At the same time, a key ingredient to lift customer participation levels in DR programs is a solid marketing campaign. Again, it is unclear whether rates in the industrial segment are cross-subsidized, if so, it would be reasonable that as part of a successful demand response marketing campaign, that this reality would be highlighted and well understood by potential DR participants. In this DR marketing campaign, without being coercive, EVN PCs should educate customers on their tariffs while highlighting the alternatives to voluntary demand response participation, one being involuntary demand response in the form of brownouts and rotational load shedding, or a government decision to implement changes to the tariff methodology to move the incentive dial in a direction that would help preserve the reliability of the system when supply is tight.

Table 2-1: 2020 Applicable Retail Electricity Tariffs

	Customer Class	**Percentage compared with the average electricity retail price adjusted under the authority (%)**	**Current Applicable Rate[13] (VND/kWh)**
1	**Electricity retail price for manufacturing sector**		
	Voltage level from 110 kV or higher		
	a) Normal hours	84%	1,536
	b) Off-peak hours	52%	970
	c) Peak hours	150%	2,759
	Voltage level from 22 kV to less than 110 kV		
	a) Normal hours	85%	1,555
	b) Off-peak hours	54%	1,007
	c) Peak hours	156%	2,871
	Voltage level from 6 kV to less than 22 kV		
	a) Normal hours	88%	1,611
	b) Off-peak hours	56%	1,044
	c) Peak hours	161%	2,964
	Voltage level of less than 6 kV		
	a) Normal hours	92%	1,685
	b) Off-peak hours	59%	1,100
	c) Peak hours	167%	3,076

[13] According to data from EVN consulted February 2020, https://en.evn.com.vn/d6/gioi-thieu-d/RETAIL-ELECTRICITY-TARIFF-9-28-252.aspx

	Customer Class	Percentage compared with the average electricity retail price adjusted under the authority (%)	Current Applicable Rate[13] (VND/kWh)
2	**Electricity retail price for administrative sector**		
	Hospitals, nurseries, kindergartens, high schools		
	Voltage level from 6 kv or higher	90%	1,659
	Voltage level of less than 6 kv	96%	1,771
	Public lighting: administrative units		
	Voltage level from 6 kv or higher	99%	1,827
	Voltage level of less than 6 kv	103%	1,902
3	**Electricity retail price for business**		
	Voltage level from 22 kv or higher		
	a) Normal hours	133%	2,442
	b) Off-peak hours	75%	1,361
	c) Peak hours	230%	4,251
	Voltage level from 6 kV to less than 22 kV		
	a) Normal hours	143%	2,629
	b) Off-peak hours	85%	1,547
	c) Peak hours	238%	4,400
	Voltage level of less than 6 kV		
	a) Normal hours	145%	2,666
	b) Off-peak hours	89%	1,622
	c) Peak hours	248%	4,587
4	**Electricity retail price for domestic purposes**		
	Electricity retail price for domestic purposes		
	Level 1: 0 – 50 kWh	92%	1,678
	Level 2: 51 – 100 kWh	95%	1,734
	Level 3: 101 – 200 kWh	110%	2,014
	Level 4: 201 – 300 kWh	138%	2,536
	Level 5: 301 – 400 kWh	154%	2,834
	Level 6: 401 kWh or higher	159%	2,927
	Electricity retail price for prepayment meter	132%	2,461

Sources: (a) Appendix to Decision 28/2014/QD-TTg dated April 07, 2014
(b) https://en.evn.com.vn/d6/gioi-thieu-d/RETAIL-ELECTRICITY-TARIFF-9-28-252.aspx

Chapter 03

DR Institutional, Legislative, and Market Framework

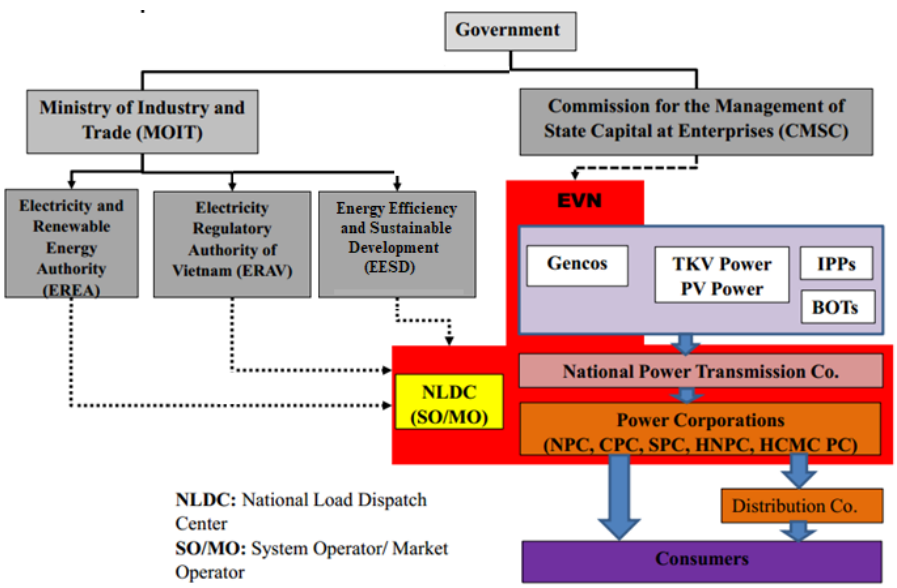
3 DR Institutional, Legislative, and Market Framework

After a rapid overview of the power sector's recent history, we look at the policies and strategies defined by the Vietnamese government as regards DR. We then examine the institutional landscape and the regulatory framework.

3.1 Brief Sector History

Until 1994, the power system in Vietnam was organized in three regional independent power companies (PC), dividing up the country in 3 geographical zones North, Centre and South, with each operating as an independent vertically integrated company. In May 1994, a 500 kilovolt transmission line was commissioned to bring power from the Hoa Binh hydropower station in Hanoi to Ho Chi Minh City. Stretching the length of the country, this was the first line interconnecting the transmission network.

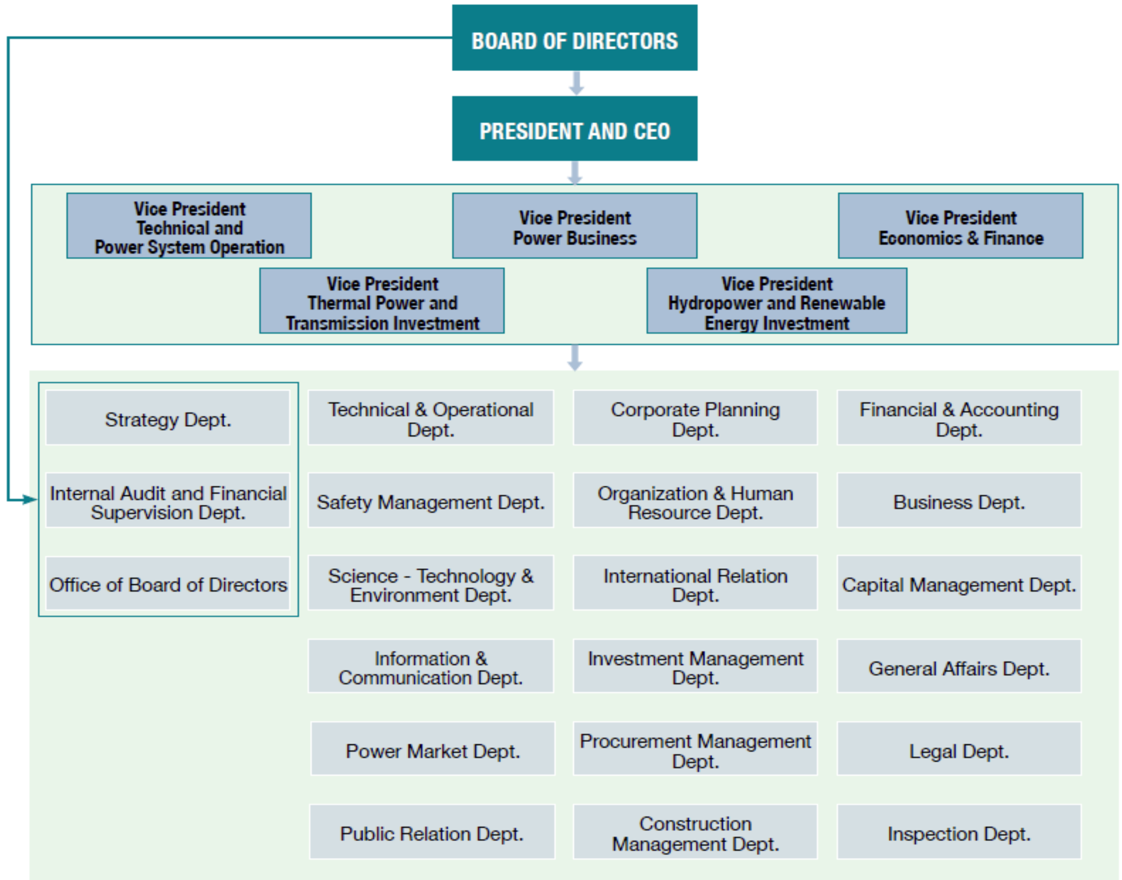
Figure 3-1: Stakeholders in the Vietnamese Power Sector



Source: ERAV

On October 10, 1994, the Prime Minister issued Decision 562/QD-TTg establishing the Vietnam Electricity Corporation (known as Electricity of Vietnam or EVN). 1995 saw a major industry reorganization with the merging of the three vertically integrated PCs to form EVN. Generation and transmission operations were restructured into functionally separate entities, while distribution was reorganized into five regionally based independent subsidiaries.

Figure 3-2: Organization chart of EVN



In 2004, a new Electricity Law came into force, which led to further restructuring of the sector. In 2006, state-owned EVN was established as a holding company[14] with EVN generation and transmission and the five power companies covering North, South, and central regions, and two urban distributors covering Hanoi and Ho Chi Minh.

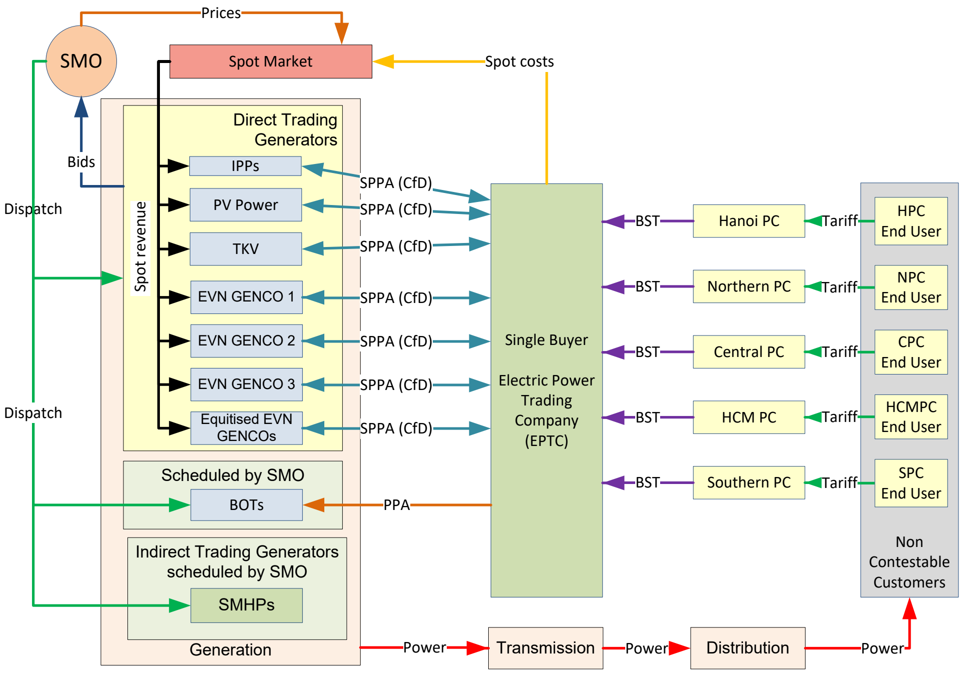
The Vietnamese electricity market continues to evolve with the gradual inclusion of additional actors in the marketplace. In 2012, the country adopted a 20-year roadmap to phase in competition in the wholesale and retail markets. Today we see competition in the generation market, with ERAV currently implementing a competitive wholesale market as of 2019. The generation segment of EVN currently accounts for over 60% of generation capacity.

[14] https://en.evn.com.vn/c3/gioi-thieu-f/Overview-2-3.aspx , visited February 2020

- On June 22, 2006, the Prime Minister of the Government issued Decision No. 147/QD-TTg approving the pilot scheme to establish the Vietnam Electricity Group and Decision No 2006/148/QD-TTg on the establishment of the parent company-Vietnam Electricity Group.
- On June 25, 2010, the Prime Minister issued Decision No. 975/QD-TTg regarding the change of the parent company-Vietnam Electricity Group into the one member limited liability company owned by the State.
- On December 06, 2013, the Prime Minister issued Decree No. 205/2013/ND-CP regarding the Charter of organization and operation of the Vietnam Electricity (the decree was effective from Feb 3, 2014

Although the private sector has been playing a larger role with the government encouraging participation, its contribution has been slower than anticipated in large part due to low tariffs[15].

Figure 3-3: Description of Electricity Marketplace in Vietnam



Source: ERAV

3.2 Applicable Policies and Strategies

3.2.1 General Electricity Context: Power Master Plan VII

On 18 March 2016, the Revised National Power Development Master Plan for the 2011-2020 period with vision to 2030 (the "Revised Power Master Plan VII") was approved. The Master Plan focuses on energy security, energy efficiency, renewable energy development and power market liberalization.

The Master Plan laid **key directions** and specific targets for the Vietnamese power sector from 2016 to 2030, as follows:

Key Direction 1: Ensure sufficient supply of electricity to meet socio-economic development targets and requirements and the people's needs;

[15] WB expert: Electricity tariff is low, Vietnam is among the top electricity consumption countries in East Asia,14/12//2017 https://en.evn.com.vn/d6/news/WB-expert-Electricity-tariff-is-low-Vietnam-is-among-the-top-electricity-consumption-countries-in-East-Asia-66-163-821.aspx, visited February 2017

Key Direction 2: Combine the efficient use of domestic energy resources with the reasonable import of electricity and diversify the primary energy resources for power generation. Give priority to the development of power generation from renewable sources; contribute to natural resource conservation; minimise negative impacts of power generation to the environment;

Key Direction 3: Develop transmission and distribution grids;

Key Direction 4: Develop 200 kV and 500 kV transmission grid in the national power transmission network to ensure safe, reliable and economic transmission; at the same time to attach great importance to development of small power generation sources from renewable energy resources;

Key Direction 5: Improve the quality of electricity and electricity services step by step and adjust the electricity tariffs according to the market mechanism to encourage investment in power sector and efficient and saving use of electricity; and

Key Direction 6: Develop competitive power market in accordance with set out roadmap to diversify investment types and trading of electricity. The State shall hold monopoly only in the power transmission network in order to ensure security of the national energy system.

Demand response addresses the imperatives contained in Key Directions 1, 2 and 5.

3.2.2 The National Demand Response Targets in the Period 2018-2030

The **overarching objectives** of demand response initiatives contained in Decision No. 279/QD-TTg[16] include economic considerations, reliability questions, and societal imperatives, as follows:

- → To ensure electricity supply, improve the quality and reliability of electricity supply, contribute to environmental protection and socio-economic development, raise the overall economic efficiency of the power system;
- → To reduce peak load capacity of the national electric system and regional electricity systems in order to reduce the need for investment capital for new construction and expansion of the electricity system; and
- → To raise the awareness of electricity users and society as a whole in the management of electricity demand and efficient use of electricity; moving from traditional electricity customers to smart electricity consumers.

[16] PM Decision dated 08/3/2018 on Approving National Program on Demand Side Management (DSM) for 2018 – 2020 with vision to 2030

The **specific objectives** attached to demand response initiatives contained in Decision 175/QD-BCT[17] include in part:

Policy Objectives

→ Develop relevant policies, financial mechanisms and supporting mechanisms to create a legal pathway for implementation DR Program under the National DSM Program umbrella;

Societal Objectives

→ Educate consumers in power demand management and efficiency; gradually shift from traditional consumers to smart consumers;

→ Combine the implementation of the DR Program with promoting consumers to invest in decentralized renewable energy sources, especially rooftop solar power systems, energy storage systems so that the DR program can have the highest performance.

System Objectives

→ With a projected load growth factor of 3-4% in the 2021-2030 period, strive to reduce at least 30% of the overall peak load, corresponding to at least 90 MW by 2020, 300 MW by 2025 and 600 MW by 2030

→ Improve the load factor of the national, regional power system, and of each PC; gradually build and expand the DR Program to each distribution substation, improve the load factor of each substation;

→ Contribute to reducing transmission losses on the North - Central - South 500kV - 220kV transmission grid;

→ Implement the DR Program ensuring that after 2020, the DR Program will be widely implemented with voluntary and proactive participation of consumers nationwide and become one of the programs and solutions to provide ancillary services for the power system, reducing the need for ancillary services by the power sources in the national power system;

3.3 Current Institutions Involved in Demand Response

At ministerial level

The specific role of the various agencies at ministerial level, which we briefly describe below, in DR implementation is contained in the Decision 279 / QD-TTg dated March 8, 2018 approving the national program on Demand Side Management in 2018 – 2020 with vision to 2030.

[17] MOIT Decision dated 28/01/2019 on Approving the Implementation Plan and Roadmap for the DR Program

Ministry of Industry and Trade (MOIT)

a) To assume the prime responsibility for organizing the implementation of the national program on DSM, ensuring the achievement of the approved objectives, contents and plans.
b) To supplement the functions and tasks of the management and implementation of the National Program on DSM into the functions and tasks of the Steering Committee for Smart Development in Vietnam (the Steering Committee). The Steering Committee is responsible for developing and improving the legal framework, implementing and monitoring the implementation of the National Program on DSM, identifying specific objectives in each phase and for each DSM.
c) In the 2018-2020 period, to assume the prime responsibility and coordinate with the concerned ministries and branches in studying, formulating and promulgating fully the legal framework, especially the financial mechanism and incentive mechanism to promote Implementation of the National Program on DSM in accordance with the provisions of Article 10 of the Government's Decree No. 137/2013 / ND-CP dated October 21, 2013 detailing the implementation of a number of articles of the Electricity Law and Law To amend and supplement a number of articles of the Electricity Law and, in case of necessity, report to the Prime Minister the contents falling beyond its competence.
d) To assume the prime responsibility for, and coordinate with the Ministry of Finance in, studying, elaborating and promulgating financial mechanisms and incentive mechanisms in conformity with the financial solutions approved in this Decision to support the implementation thereof. The DSM Programs and the DR Program, including mechanisms for managing and monitoring implementation in accordance with the financial solutions approved in this Decision.
e) Coordinate with the Ministry of Education and Training in organizing training materials on the contents and benefits of the DSM programs and the national program on DSM for reference by schools in the curriculum, suitable for the level of training students.
f) Research, formulation and promulgation of a legal framework and policy mechanism for the establishment and operation of service delivery units / units Coordinating DSM / DR activities in line with sectoral development conditions. Vietnam electricity and trends in the world.
g) In 2018, the organization shall formulate and approve in detail the roadmap and plan for the implementation of DR programs, ensuring that it conforms to the mechanism, policies and conditions for development of the Vietnam power systems and Smart Grid Development Program.
h) Study and propose directions for development and distribution of additional electricity in accordance with the distribution and structure of power sources in the electricity system to contribute to the implementation of the objectives of sustainable development of the power sector and the energy sector.
i) Promote international cooperation and make use of resources provided by international financial institutions to implement technical assistance projects to develop and perfect the institutional and legal framework for implementation. the content of the DSM National Program.
j) Organizing the implementation of awareness programs of the society, customers of electricity and electricity units on the National Program on DSM.

k) Annually, organizations shall elaborate plans and assign quotas to implementing units so as to achieve the objectives already approved in this Decision; To closely supervise the implementation of the contents and programs of the national program on DSM.
l) During the implementation of the National Program on DSM, the Ministry of Industry and Trade is responsible for reviewing and evaluating implementation results to propose the Prime Minister to consider and approve additional or revised targets.

Ministry of Finance
Cooperate closely with the Ministry of Industry and Trade to study, formulate and promulgate or submit to competent authorities for promulgation financial mechanisms, electricity pricing mechanisms and incentive mechanisms to support the implementation of the DSM and The DR program, including the management and monitoring mechanism, is in line with the financial solutions approved in this Decision.

Ministry of Education and Training
Coordinate with the Ministry of Industry and Trade to develop training materials on the content and benefits of the DSM Programs and the National Program on DSM for schools to refer to the Education Program to train pupils and students.

Electricity of Vietnam (EVN)
EVN and its subsidiaries shall have to:

a) EVN shall direct the power corporations, power companies and attached units to fully and synchronously implement the national program on DSM approved in this Decision 279 and relevant legal documents and guiding documents.

b) Develop a plan and implement the contents of the National Program on DSM, which specifies the annual targets and targets to ensure the achievement of the specific objectives of the National Program on DSM.

c) To concentrate and step up the implementation of the electricity charge study, to comprehensively exploit the results of the electric load study to assess the potential for the implementation of the DSM programs, the DR program, monitoring and management. Comply with the diagram of electricity load of customers using electricity, especially the customers who contributed and influenced the load chart.

d) To invest in and upgrade the power system, information technology system and infrastructure in service of the implementation of the DSM programs, the DR program, especially the infrastructure system advanced counting, meter reading system and remote metering data collection. Report on the results of implementation of contents and programs in the national program on DSM according to regulations and requirements of the Ministry of Industry and Trade.

e) Organize the implementation of the National Program on DSM in line with organizational structure, operational efficiency and practical conditions at power units.

f) Strengthening implementation of social awareness programs, electricity customers and electricity units on the content of the National Program on DSM and the benefits of the DSM programs.

Provincial People's Committees

Provincial People's Committees have the following responsibilities

a) Develop appropriate programs and solutions to support the implementation of the National Program on DSM of electricity units and customers under their management; The objective of the National Program on DSM is to integrate the socio-economic development plan and local production plan into each period of development; Arrange appropriate resources to implement the contents of the National Program on DSM and efficient use of electricity.

b) To inspect, monitor and report to the Ministry of Industry and Trade on the results of implementation of the national program on DSM, efficient use of electricity by electricity units and customers under their management; To promptly handle according to their competence cases of failing to strictly comply with the provisions of law on management of electricity demand and efficient use of electricity.

Customers:

Customers using electricity and other related power units are responsible for participating in the implementation of the DSM Program in the National Program on DSM.

<u>At MOIT level:</u>

Decision 175/QD-BCT provides institutional arrangement for Departments and Authorities under MOIT involved in DR implementation.

ERAV

a) Preside and coordinate with EVN and agencies under the Ministry of Finance to study, build and submit to relevant authorities for promulgation supporting mechanisms including financial for DR Program implementation, ensuring compliance with the financial solutions approved in the National DSM Program;
b) Study, develop and submit to the relevant authorities for promulgation of other necessary legal documents to build a comprehensive legal corridor for DR Program implementation;
c) Develop the DR Program implementation plan to be integrated in the annual work plan of the Vietnam Smart Grid Development Steering Committee and submit to the Steering Committee for approval;
d) Lead and coordinate with EVN and relevant units to work with the Ministry of Education and Training and organized customized/specialized training, develop training materials and conduct the training on DR Program;

e) Appraise and approve the objectives of the annual and periodical implementation plans of the National DSM Program and DR Program in combination with the annual work plan of the Vietnam Smart Grid Development Steering Committee;

f) Monitor, supervise, urge, inspect and evaluate the annual and periodical performance of the DR Program in the overall National DSM Program according to the approved roadmap and plan;

g) Actively promote international cooperation, leverage supports of domestic and international organizations to implement technical assistance, pilot programs, build and improve the legal framework, capacity for the approved DR Program implementation;

h) During the DR Program implementation, ERAV shall review and evaluate the results to propose to the Minister of Industry and Trade for supplement or adjustment of the DR Program's objectives.

EVN

a) EVN plays the key role in DR Program implementation, ensure the achievement of the objectives and contents approved in this Decision in accordance with current policies and mechanisms;

b) Coordinate closely with ERAV, the Ministry of Finance and relevant units to develop and improve the legal framework and policies for the implementation of the DR Program and the National DSM Program;

c) Fully and synchronously implement, and disseminate the DR Program contents approved in this Decision to subordinate units; proactively build a comprehensive and specific program implementation plan for the pilot, expansion (from smaller to larger scale) and wide deployment in relevance with each phase and content of the DR Program. If necessary, prepare a scheme for DR Program implementation in the period of 2019-2020, with a vision towards 2030, to be reported to MOIT through ERAV;

d) Build and implement the communication strategy, public awareness raising programs to disseminate contents and benefits of the DR Program and the National DSM Program for step by step implementation from 2019;

e) Direct and assign PCs to perform the following tasks:

- Promote demand study, improve demand forecasting capacity, comprehensively use the demand study's results to assess the DR Program and National DSM Program's potential;
- Develop a plan and implement the DR Program as an activity and solution in the annual business plan to optimize production and business performance of each unit as well as EVN;
- Build a complete statistical database of 2017 including the load factor, maximum capacity of the power system under its management, load chart (power system, substation, consumers, etc.), the number of consumers, divided into different categories by load component, load study's findings, etc. to be used as a basis for setting objectives, monitoring and evaluating the performance of DR Program and National DSM Program for each year and period;
- In 2019, conduct study and assess the potential of the DR Program for each

region and target consumers;

- Implement the DR Program in accordance with the roadmap and plan approved in this Decision and the Regulation on the content and order of DR program promulgated by the Ministry of Industry and Trade;
- Review and organize the implementation of the DR Program in the National DSM Program to ensure conformity with the organizational structure, efficiency and actual conditions at the power agencies; promote capacity building for staff and specialized divisions to implement the DR Program;
- Develop and issue internal procedures to guide staff and consumers on DR Program registration;
- Provide trainings for the staff in charge of the DR Program implementation, especially officers working directly with consumers;
- Invest and upgrade power system, IT, infrastructure, meter reading and remote data collection, DR Program implementation and management systems and step by step build an advanced metering infrastructure to effectively implement the DR Program;
- Invest in distribution grid automation and control system (OMS, SAS, DAS, GIS, etc.) in accordance with the Smart Grid development orientation of Vietnam to support the efficient and optimal implementation of DR Program;

f) Develop an annual and periodical implementation plan and objectives in line with the approved DR Program and the National DSM Program and submit to the Ministry of Industry and Trade for consideration and approval in the annual work plan of Smart Grid Development Steering Committee.

g) Actively promote international cooperation, take advantage of supports from domestic and international organizations to implement pilot projects and programs in accordance with the DR Program approved hereof;

h) Quarterly report to the Ministry of Industry and Trade through ERAV on the implementation results of EVN and each PC.

Electricity & Renewable Energy Authority (EREA):

- Study and propose specific orientations, solutions for the power mix in accordance with the load distribution in the PDP to contribute to the sustainable development goal of the power sector and energy sector;
- Coordinate with ERAV in studying and proposing mechanisms and policies for the implementation of the DR Program integrated into the PDP to reduce pressure for investment in power systems, renewable energy development.

Energy Efficiency and Renewable Energy Agency (EESD):

Coordinate with ERAV to study, propose solutions and mechanisms to combine the implementation of the DR Program with the EE Program to leverage resources to achieve the highest efficiency

Department of Science and Technology:

Lead, coordinate with ERAV, EVN and relevant agencies in implementing scientific and technological tasks related to the National DSM Program integrated with tasks of national-level science and technology programs and projects and the Ministry of Industry and Trade.

Department of Finance and Enterprise Innovation:

Allocate additional funding from the budget for the operation of the Smart Grid Development Steering Committee after supplementing functions and tasks on the approved National DSM Program implementation and management.

Others:

Journal of Industry and Trade, Industry and Trade Newspaper, Research Institutes and Training Schools under the Ministry of Industry and Trade cooperate with ERAV to develop and implement trainings, communication and awareness raising programs on the content and benefits of the DR Program and the National DSM Program.

Entities under EVN:

In decision 54/QD-DTDL dated June 12th, 2019 by General Director of ERAV, the involvement of different entities under EVN has been clarified. It includes EVN itself and associated supporting departments or centers, 5 Power Corporations and other Power companies.
EVN's main subsidiaries are:

- 3 Power generation corporations (GENCO 1, 2, 3);
- 5 distribution companies commonly referred to as Power Corporations (PCs), namely, Northern Power Corporation (EVNNPC), Central Power Corporation (EVNCPC), Southern Power Corporation (EVNSPC), Hanoi Power Corporation (EVNHANOI), the Ho Chi Minh City Power Corporation (EVNHCMC);
- The National Power Transmission Corporation (EVNNPT); and
- The National Load Dispatch Centre (NLDC), the system operator and system planner which plays an operational role in DR implementation

The parent EVN will assign the following tasks to the PCs:

a) Promote demand study, improve demand forecasting capacity, comprehensively use the demand study's results to assess the DR Program and National DSM Program's potential;

b) Develop a plan and implement the DR Program as an activity and solution in the annual business plan to optimize production and business performance of each unit as well as EVN;

c) Build a complete statistical database since 2017 including the load factor, maximum capacity of the power system under its management, load chart (power system, substation, consumers, etc.), the number of consumers, divided into different categories by load component, load study's findings, etc. to be used as a basis for setting objectives, monitoring and evaluating the performance of DR Program and National DSM Program for each year and period;

d) In 2019, conduct study and assess the potential of the DR Program for each region and target consumers;

e) Implement the DR Program in accordance with the roadmap and plan approved in this Decision and the Regulation on the content and order of DR program promulgated by the Ministry of Industry and Trade;

f) Review and organize the implementation of the DR Program in the National DSM Program to ensure conformity with the organizational structure, efficiency and actual conditions at the power agencies; promote capacity building for staff and specialized divisions to implement the DR Program;

g) Develop and issue internal procedures to guide staff and consumers on DR Program registration;

h) Provide trainings for the staff in charge of the DR Program implementation, especially officers working directly with consumers;

i) Invest and upgrade power system, IT, infrastructure, meter reading and remote data collection, DR Program implementation and management systems and step by step build an advanced metering infrastructure to effectively implement the DR Program;

j) Invest in distribution grid automation and control system (OMS, SAS, DAS, GIS, etc.) in accordance with the Smart Grid development orientation of Vietnam to support the efficient and optimal implementation of DR Program;

The relationship between Power Companies (DR implementing entities) and customers is described in the charts below:

Figure 3-2: During the registration process

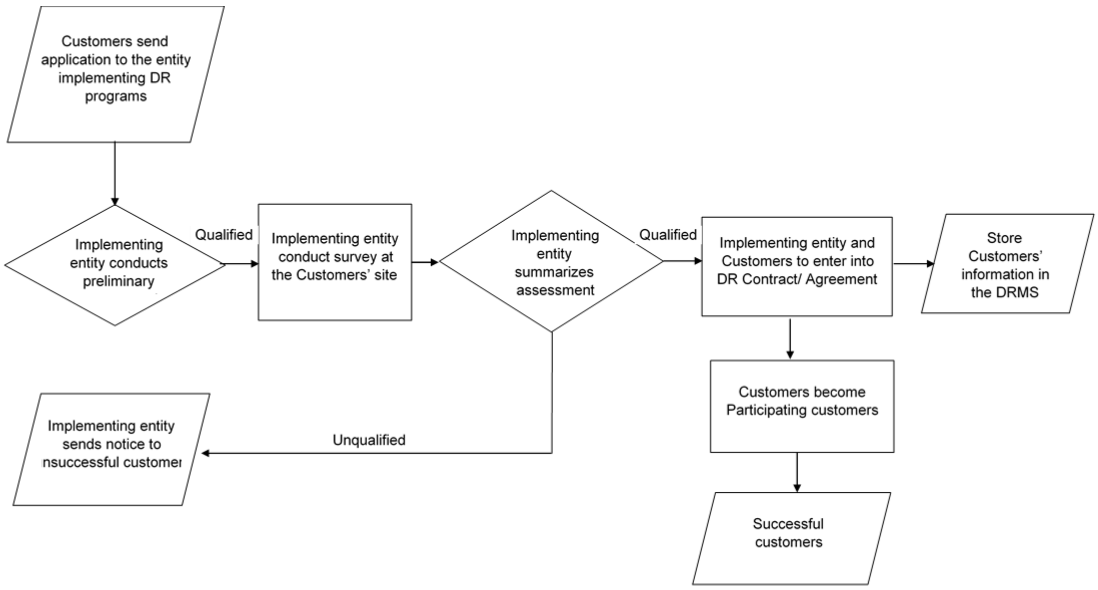
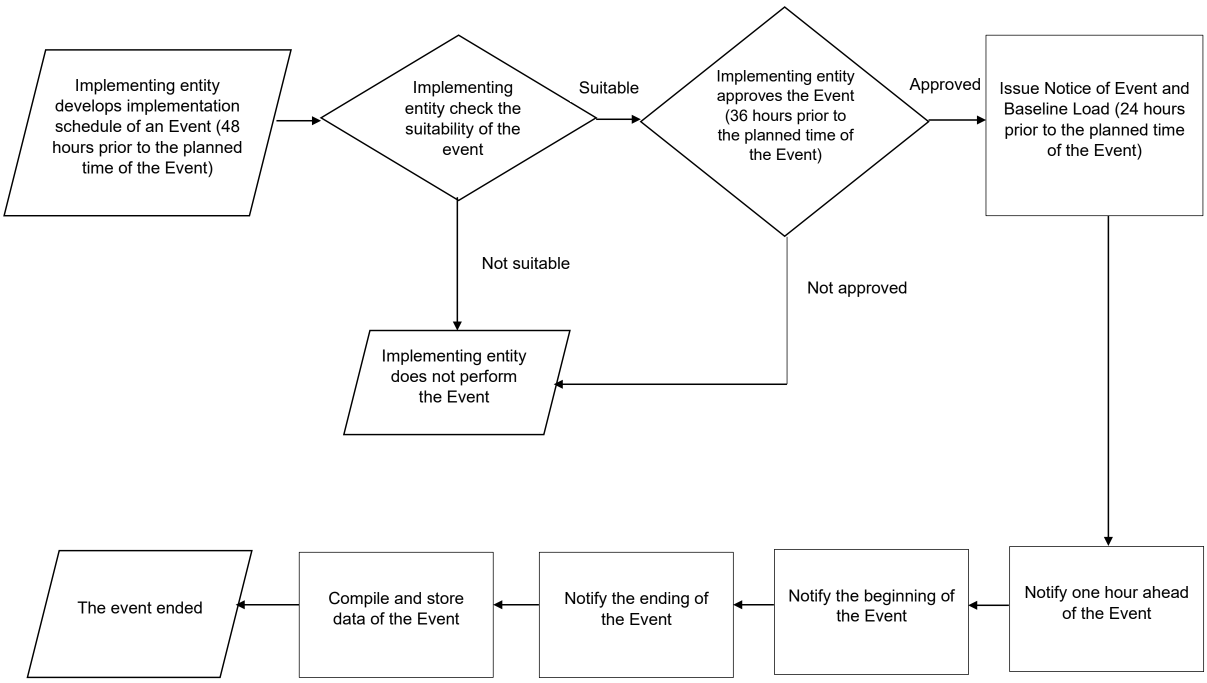


Figure 3-3: During the event implementation process

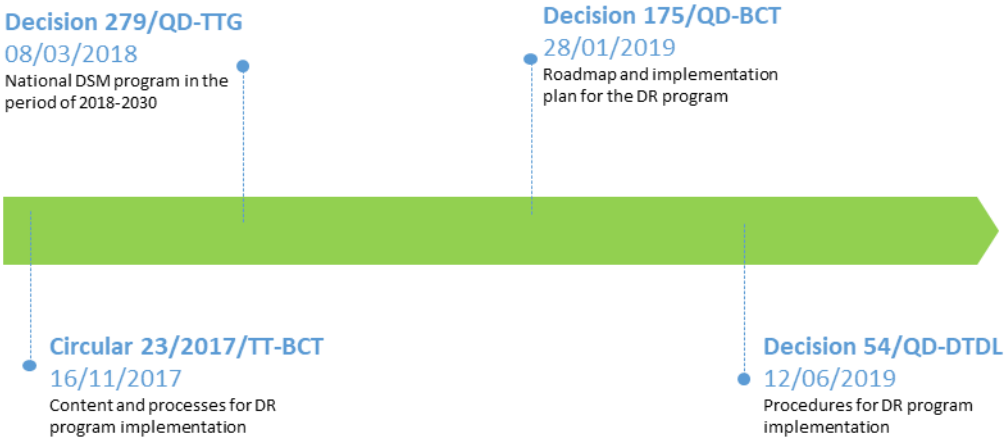


3.4 Summary of DR Related Legislative and Regulatory Instruments to Date

3.4.1 Overview

Decisions 279 (Vision to 2030), 175 (Implementation Roadmap), and 54 (Implementation Procedures) and Circular 23 (Content for DR Programs) set the overall framework in which demand response is being developed and implemented.

Demand response related regulation should be read within the framework formed by these four main documents.



3.4.2 DR programs defined in Circular 23

The programs identified in Circular 23 fall in the following two categories, economic based programs and reliability based ones.

Economic based DR programs are designed to enhance the sector's efficiency by reducing the costs of operation, in particular to avoid the high cost of power when import prices are high, or to avoid the need for capital expenditure in new peaking capacity or in network upgrades/expansions.

Reliability based DR programs are driven by the need to ensure power system reliability and avoid the overloading of network equipment, and/or to alleviate tight supply and demand conditions. Reliability based programs deploy demand response in the event that power system conditions require it.

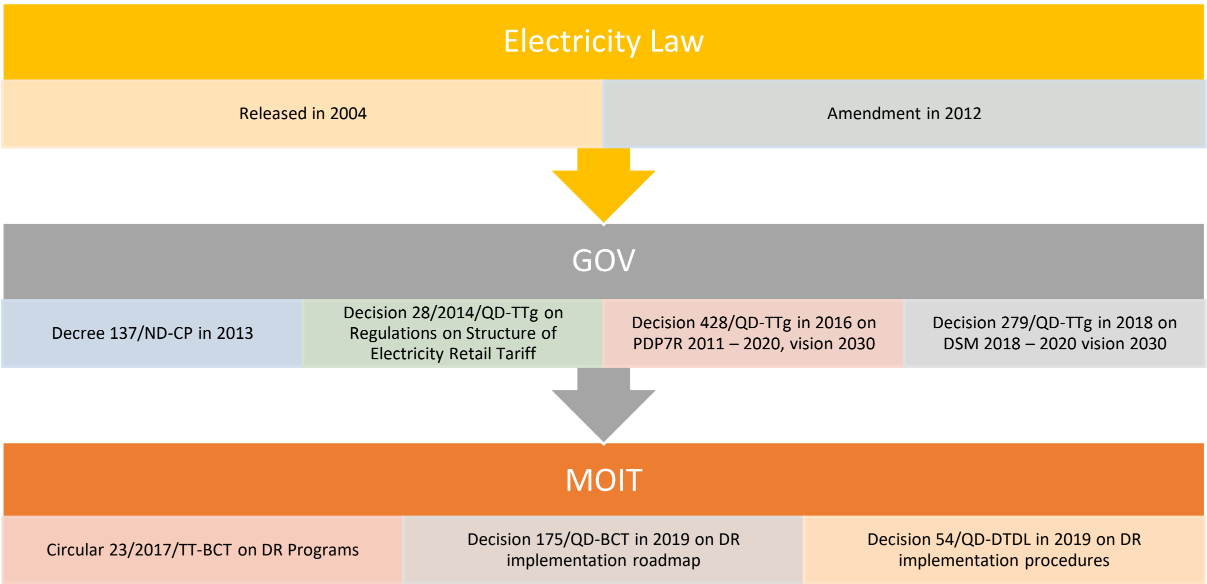
All 4 types of programs identified in Circular 23 are further described in the following table.

Dispatchable Incentive-based DR Programs
Curtailable Load Program - CLP (voluntary program, targeted to industrial and commercial customers those have flexible production lines with consumption from medium - scale to large - scale). The CLP is an economic based program and is designed to drive efficiency, and reduce the cost of production for the marginal unit of electricity.
Emergency Demand Response Program - EDRP (voluntary program, targeted to industrial and commercial customers those have flexible production lines with large scale of consumption, and able to change or reduce electricity demand quickly). The EDRP is designed to ensure power system reliability, demand response is deployed in the event that the power system is overloaded.
Non-dispatchable Time-based DR Programs

Two-tiered electricity tariff program (Demand charge and Energy charge; targeted to customers who have already been on Time of Use tariff). Customers actively decide to adjust or change their demand to respond to price signals, especially within peak time to reduce electricity billing.
Real-time Peak load electricity-tariff program (voluntary program, targeted to industrial and commercial customers). The tariff includes TOU tariff and special tariff for peak time (the peak time will be announced on a case by case/time-to-time by authorized operators).
Non-commercial DR Programs
In this model, there is no financial incentive. Reward can be "payment" is in the form of preferential treatment should load curtailment be implemented as a last resort measure to maintain integrity of the power system.
Voluntary DR Programs
As envisaged in Circular 23, in this model, there is no financial incentive. Reward may be in the form of goodwill as the customer is seen as contributing to societal good. It is unclear whether and how a corporation could incorporate this Goodwill in its accounting system.

3.4.3 Other laws and regulations that directly relate to demand response are:

- Electricity Law (28/2004/QH11 and revision 24/2012/QH13)
- Decision 2447/QD-BCN dated July 17, 2007, from MOIT on approving the national program for power demand side management (DSM 2007 – 2015)
- Decision 1670/QD-TTg dated 8/11/2012 of Prime Minister approving Smart Grid Development Program in Vietnam
- Decree 137/2013/ND-CP dated 21/10/2013 regulated detail implementation of Electricity Law and its revision, amended few articles of that Law
- Circular 19/2017/TT-BCT dated 29/9/2017 of MOIT related to methodology and process for demand side study
- Circular 23/2017/TT-BCT dated 16/11/2017 of MOIT on Prescribing Content and Processes for Implementation of Load Adjustment Programs.
- Letter 6017/BCT-DTDL dated 31/7/2018 of Minister of MOIT related to implementation of DR program for 2018 – 2020, with vision to 2030
- Decision 279/2018/QD-TTg dated 8/3/2018 of Prime Minister approving National program on Demand Side Management (DSM) for 2018 – 2020 with vision to 2030
- Decision 175/QD-BCT dated 28/01/2019 of Minister of MOIT on Approving the Implementation Plan and Roadmap for the DR Program
- Decision 54/QD-eL dated 12/06/2019 of Minister of MOIT on the Determination of Procedures for Implementing the Electrical Load Control Program

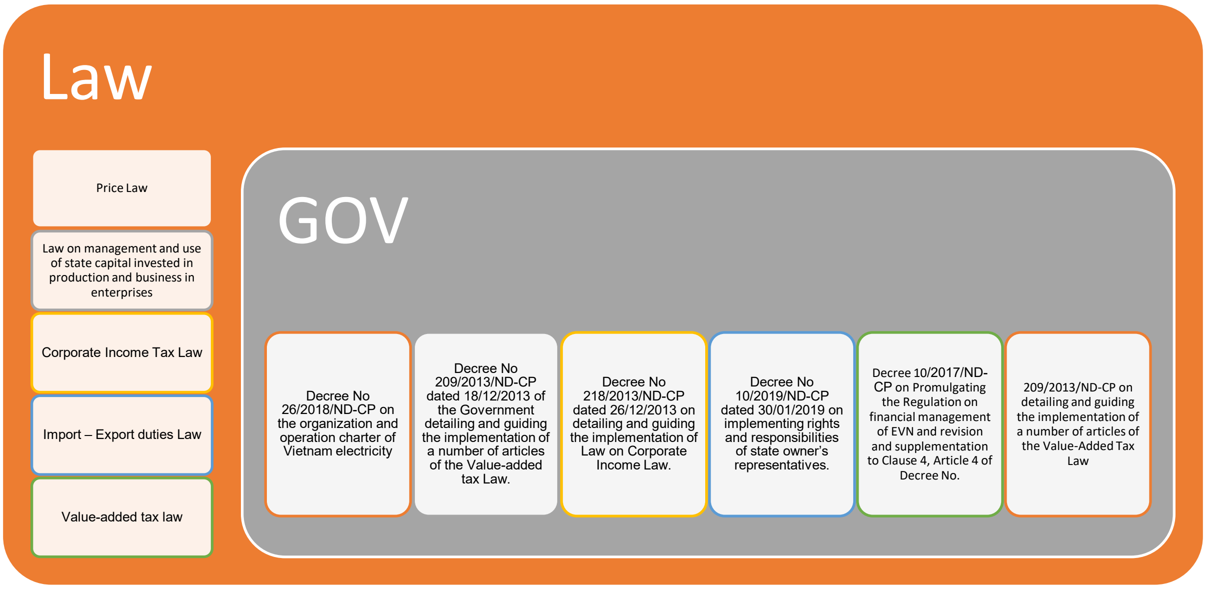


3.4.4 Laws and Regulations that may indirectly affect the implementation of demand response

The laws and regulations that may indirectly affect the implementation of demand response largely relate to instruments that involve state-owned enterprises, financial, pricing provisions.

- Price Law (Law No. 11/2012/QH13 dated 20/06/2012)
- Law on management and use of state capital invested in production and business in enterprises
- Corporate Income Tax Law (Law No 14/2008/QH12 dated 03/6/2008); Amendments to the law on Enterprise Income Tax (Law No 32/2013/QH13 dated 19/6/2013). Thus, the revenues used to calculate taxable income generated from sale of goods and services (including subsidies and surcharges) regardless of whether or not the money has been collected. Beside, companies and corporations will have deductible and non-deductible expenses when determining taxable income.
- Import – Export duties Law (Law No 107/2016/QH13 dated 06/4/2016)
- Value-added tax law (Law No 13/2008/QH12 dated 03/6/2008)
- Decree No 26/2018/ND-CP dated 28/2/2018 on the organization and operation charter of Vietnam electricity.
- Decree No 209/2013/ND-CP dated 18/12/2013 of the Government detailing and guiding the implementation of a number of articles of the Value-added tax Law.
- Decree No 218/2013/ND-CP dated 26/12/2013 on detailing and guiding the implementation of Law on Corporate Income Law.
- Decree No 10/2019/ND-CP dated 30/01/2019 on implementing rights and responsibilities of state owner's representatives.
- Decision 28/QD-TTg dated 7/04/2014 of Prime Minister on Electricity retail tariff's structure
- Decision 24/2017/QD-TTg dated 30/06/2017 of Prime Minister on Mechanism for adjustment of average electricity price

- Decree 10/2017/ND-CP dated 9/02/2017 on Promulgating the Regulation on financial management of EVN and revision and supplementation to Clause 4, Article 4 of Decree No. 209/2013/ND-CP dated December 18, 2013 of the Government detailing and guiding the implementation of a number of articles of the Value-Added Tax Law
- Decision 1208/QD-TTg dated 21/07/2011 of Prime Minister approving national power development plan 2011 – 2020, with vision to 2030
- Decision 428/QD-TTg dated 18/03/2016 of Prime Minister on the Approval of the Revised National Power Development Master Plan (VII) for the 2011-2020 Period with the Vision to 2030
- Decision 3771/QD-BCT dated 10/02/2017 defining the functions, tasks, powers and organizational structure of the Electricity Regulatory Authority (ERAV)



3.4.5 Communication between MOIT and MOF that Relate to DR

The method for the recovery of demand response related incentives from ratepayers requires certain approvals of the Ministry of Finance to ensure that the methodology does not encroach on any laws that may govern state-owned EVN. We list several letters containing important communication between the two ministries.

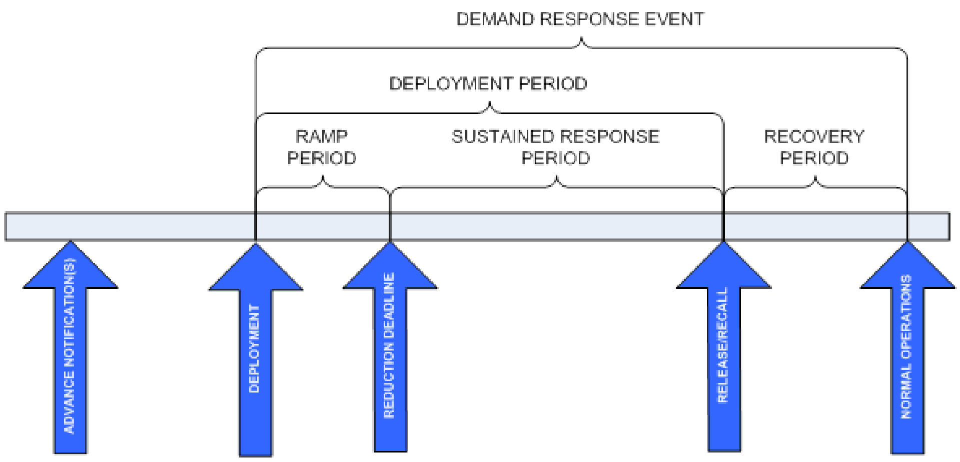
- Letter 6017/BCT-DTDL dated 31/7/2018 of Minister of MOIT related to implementation of DR program for 2018 – 2020
- Letter 6309/BCT-TKNL from MOIT to MOF dated 9/08/2018 Related to coordination to unbundle challenges to promote ESCO market and issues of DSM implementation by EVN
- Letter 10192 /BCT-TKNL from MOIT to MOF dated 31/12/2019 containing Comments on the Development of an Energy Service Market and Demand-side Management

- Official Dispatch no. 3609/BTC-TCDN titled Comments on Some Issues Related to the Development of the Energy Service Market and Demand-side Management ("Letter 3609") dated 27/03/2020 in which MOF provided its reply to Letter 10192.
- On February 12, 2018, the Ministry of Finance sent official dispatch No. 1878/BTC-TCDN to Vietnam Electricity (EVN) on guiding the financial mechanism of energy saving projects base on service model (ESCO).

3.4.6 ERAV Decision 54 (54/QD-DTDL, 12 June 2019)

Decision 54 outlines procedures for the load adjustment program (or DR program), it **covers both Curtailable Load Program (CLP), and the Emergency Demand Response Program (EDRP).** Decision 54 is an important technical guidance for implementation of demand response events.

Decision 54 contains 9 articles with 4 annexes attached to describe procedures for participation registration, baseline calculation, event implementation and impact assessment, which address the scope, application, definitions, responsibilities, registration, baseline survey of customers, agreement template, opting out process, and implementation procedures. The decision also contains several technical attachments, one of which contains procedures for participation, and calculation methodologies for baseline loads, power reduction of participating customers, and incentives.



Source: NAESB

Additional detail on the Calculation of Baseline Load Curves and the Calculation of Adjustments and Incentives (Capacity calculation; Reduced Power Output Calculation; Incentive calculation) is provided at **Appendix A.**

3.5 Financing DR in Vietnam: MOF's Reply to MOIT/ERAV's Letter 10192 /BCT-TKNL dated 31 December 2019

3.5.1 Context

During consultations, we recorded that the biggest concern for all PCs and EVN corporate, as well other players involved, was by enlarge the provision of appropriate financial incentives to not only induce customer participation but to maintain participation levels in the long run.
In the Task 1 Report: Review of Existing Regulatory Frameworks for DR Program Implementation, the current state of deliberations for concerned government agencies relative to financing and incentive mechanisms was discussed. In particular, the Consultant covered communication from the Ministry of Industry and Trade (MOIT) labelled as Letter 10192/BCT-TKNL dated 31/12/2019 ("Letter 10192") addressed to the Ministry of Finance (MOF) which contained an Annex titled "Review Results and Proposal to Deal with Challenges for Energy Service Market Development and Demand-side Management".

In the Task 1 Report, the jurisdictional issues that arise from the legal provisions that bind EVN as a state-owned enterprise were identified as a barrier to the implementation of DR programming and the selection of a financing mechanism through tariffs. In fact, certain legal provisions contained in the Corporate Income Tax Law and Decree 10[18] directly affect the potential mechanism to finance DR. EVN and its subsidiaries have to abide, for accounting purposes, by the prescribed accounting rules for state-owned entities. The preliminary assessment highlighted that the recording of demand response related expenses in operating expenditures for EVN and its subsidiaries was an issue; therefore, the recognition of these expenses for cost recovery purposes was in a grey zone until MOF would opine officially on the matter. We addressed in the Task 1 Report the historical interaction between ERAV/MOIT and MOF. In particular, we noted that following the EVNHCM Pilot experience in 2015, which was funded through the Science and Technology Fund, and that at the pilot stage already initial discussions between ERAV/MOIT and MOF regarding the possibility of financing DR programming through tariffs raised several red flags for MOF. Four years after, the issue of how to finance DR remained on the table. The latest written communication from MOIT was Letter 10192. This last piece of communication focused on the necessity for the two ministries, MOIT and MOF, to reach consensus to derive the monetary value of demand response and generate the appropriate incentive mechanisms to induce and maintain participation levels in the targeted demand response programs.

Some of the key elements raised by MOIT/ERAV in Letter 10192:

- The letter noted that while the cost of financial incentives to participating customers can be sourced from a fund for DR program, the establishment of such fund is not yet possible in Vietnam. It is unclear why the setting up of a fund is not a possibility, other than the fact that competent authorities have to

[18] Decree No. 10/2017/ND-CP dated 09/02/2017
Clause 5, Article 25 states that: "EVN determines the deductible expenses for calculating taxable income under Law on Corporate income tax and current guiding documents".
Clause 1, Article 26 states that: " EVN must strictly manage its expenses to ensure that those costs are reasonable and valid under the taxaxion laws and regulations"

create it. In any event, as a result, Letter 10192 did not propose the establishment of any fund to the Prime Minister.
- Instead, MOIT suggested that DSM/DR implementation costs be recognized as eligible cost and accounted for as operating expenses, to be recovered through retail tariffs.
- MOIT's letter did address at length the role in the market of energy services providers (ESCOs) although mostly in the context of energy efficiency rather than demand response.

3.5.2 MOF's Reply

On 27 March 2020, MOF provided its reply in Letter 3609/BTC-TCDN titled Comments on Some Issues Related to the Development of the Energy Service Market and Demand-side Management ("Letter 3609").

Letter 3609 addresses two main issues, **the micro policy matter related to the regulatory accounting issue respecting the recognition and classification of DR expenses, and a macro matter related to financial solutions that the market, expressly energy services companies (ESCOs) may offer to implement the nationwide DR programs.**

a. As regards the regulatory treatment of DR related costs, MOIT's proposal that incentives expensed to compensate DR program participants be considered as reasonable costs and as such be included into the "production and business cost", and recoverable through rates, MOF reaffirmed that the Law on Corporate Income tax does not offer a finite answer and there may be some wiggle room in the legal provisions to help the regulator adopt a financing mechanism through tariffs as is the case in most jurisdictions with deep DR experience. For completion, with respect to the Law on Corporate Income Tax, MOF's reply stated:

    > *According to the Law on Corporate Income Tax (CIT), enterprise shall not count the expenses that are not corresponding to taxable income as deductible expenses (point k, clause 2 Article 9 of Decree No. 218/2013/ND-CP of the Government).*

    MOF observed that there may two avenues to finance DR incentives. One route would use the same mechanism as applied during the EVNHCMC pilot leveraging provisions under the Law on Scientific and Technological Development. The second route relates to the definition of what is considered a direct expense under the Law on Corporate Income Tax, it may take longer to adopt but may be more appropriate if lasting effects are considered and predictability favoured. A direct expense[19] is cost recoverable. MOF notes that

[19] MOF's Letter 3609/BTC-TCDN states: "As such, it is necessary to study and consider the incentive for consumers who participate in the DSM/DR programs under the CIT Law and other legal provisions, with directions as follows:

- If they are direct expenses related to electricity production and business activities (electricity generation, transmission or distribution) and has fully invoices and evidence, they are included in deductible expenses when determining taxable income under the CIT law and its regulations.

direct expenses are those that relate to electricity production and business activities such as electricity generation, transmission or distribution.
There is a large amount of material written on whether to consider demand response as "negative generation" in its role as supply insurance. While some scholars argue in favour of the "negawatts" DR brings to the system, others do not support defining and valuing DR that way. Regardless, MOIT can certainly argue the case for considering DR's "negative generation" as a direct expense like "positive generation". MOF noted however that it does not make that call and has referred MOIT to other government institutions.

In Letter 3609, MOF recommends that MOIT takes its case to The Commission for the Management of State Capital and Enterprises (CMSC) to study and clarify the definition of a what constitutes a direct expense. MOF made reference to Decree No. 10/2019/ND-CP dated 30/01/2019 on the Implementation of Rights and Responsiblities of State Owner's Representatives, which states in Clause 1, Article 5:

> *The Commission for the Management of State capital at enterprises will request the authorities to submit to the Government: promulgate, amend and suplement the 100% state-owned enterprise's charter regulations that are established by the Prime Minister's decisions and of which management is authorized to the Committee in accordance with the Government's regulations; promulate, amend and supplement the financial management regulations of the Vietnam oil and gas group, and the Vietnam electricity.*

b. MOF also weighted on what financial solutions outside of EVN could be found in the market through energy services companies (ESCOs) to implement the nationwide DR programs.

While MOF pointed to the shortcomings of the Law on Energy Efficiency and Conservation which it says have not provided guidance on the ESCO operations and management regulations, it recommended that MOIT actively promote the dissemination and application of ESCO solutions toward effective implementation of the national DSM program, stating:

> *[…] Clause 3, Article 1 of Decision No. 279/QD-TTg dated 8/3/2018, there are some financial solutions to implement the national DSM program, which include encouraging electricity entities, consumers to allocate capital proactively to invest infrastructure, information technology systems and energy management systems within their management to support the optimal and effective implementation of DSM programs; take advantages and combine the Fund for Scientific and Technological Development, and investment capital sources of energy efficiency programs.*

- If these expenses are associated with scientific research programs under the Law on Scientific and Technological Development, they should be used from the scientific and technological fund in compliance with regulations."

3.5.3 Closing Remark

Based on MOF's reply letter, we understand that there may be scope for modifying or specifying the Law on Corporate Income Tax to define DR expenses as direct expenses so that there are eligible for cost recovery through tariffs. While this is the solution that offers the clearest path for expensing DR incentives and financing a nationwide program, realistically this may take a number of months, possibly years, while the need for implementation of the nationwide government mandated DR is under way. While energy efficiency is the DSM cousin to DR, and many of the principles applicable to one are transferrable to the other, and while we recognize that EE is largely driven by permanent measures and DR by periodic events, with incentive mechanism issues in EE much less complex than in the context of DR, since Vietnam is currently also implementing energy efficiency initiatives, the Consultant believes it useful to examine funding mechanisms and financing models in the context of energy efficiency to help explore the appropriate solution for financing DR in Vietnam.

3.6 Conclusion

This chapter allows us to answer Key Questions #2 and #3: Is there a clear policy, strategy and implementation program regarding DR? Is the existing institutional and regulatory framework appropriate to implement the program?

To close this chapter, we will say that:

- With the exception of compensation mechanisms and measurement and evaluation protocols, overall there are clear policy, strategy and implementation instruments to successfully pursue a sustained DR vision.
- There is clear delineation of responsibilities between institutions.
- Communications within EVN, from NLDC (who develops the annual DR plan), to the Business department (who monitors Power Corporations/Power companies in particular and business activity of EVN in general), to Power Corporations/Power companies, need to improve with regards to explaining the rationale and need for specific DR events to the PCs, as well as the impact of DR events on local peaks related to the distribution systems and the impact on the national transmission system.
- There are complexities associated with legislation and how it impacts any DR compensation design in the future.

Chapter

04

DR Implementation: Experiential Feedback from EVNHCM DR Pilot and DR Implementation Test Year 2019

4 DR Implementation: Experiential Feedback from EVNHCMC DR Pilot and DR Implementation Test Year 2019

4.1 Implementation status of DR Programs

The programs identified in Circular 23 (see section 3.4.2) stand at various levels of implementation, as shown in the table below.

Table 4-1: Implementation status of DR Programs

Program	Status of Implementation
Dispatchable Incentive-based DR Programs	
Curtailable Load Program - CLP (voluntary program, targeted to industrial and commercial customers those have flexible production lines with consumption from medium - scale to large - scale).	2019 Pilot (without incentive) Scaling Planned (beyond 2020)
Emergency Demand Response Program - EDRP (voluntary program, targeted to industrial and commercial customers those have flexible production lines with large scale of consumption, and able to change or reduce electricity demand quickly).	2019 Pilot (without incentive) Scaling DR Planned (beyond 2020)
Non-dispatchable Time-based DR Programs	
Two-tiered electricity tariff program (Demand charge and Energy charge; targeted to customers who have already been on Time of Use tariff). There is no direct financial incentive mechanism for this program, customers need to actively decide to adjust or change their demand to respond to price signals, especially within peak time to reduce electricity billing.	Not in Scope[20]
Real-time Peak load electricity-tariff program (voluntary program, targeted to industrial and commercial customers). The tariff includes TOU tariff and special tariff for peak time (the peak time will be announced on a case by case/time-to-time by authorized operators).	Planned (beyond 2020)
Non-commercial DR Programs	
In this model, there is no financial incentive. Reward can be "payment" is in the form of preferential treatment should load curtailment be implemented as a last resort measure to maintain integrity of the power system	2019 Scaled DR
Voluntary DR Programs	
As envisaged in Circular 23, in this model, there is no financial incentive. Reward may be in the form of goodwill as the customer is seen as contributing to societal good. It is unclear whether and how a corporation could incorporate this Goodwill in its accounting system.	Not in Scope

The **EVNHCMC pilot** was on a voluntary basis and included curtailable load and emergency demand response only, with some financial incentive.

[20] "*Not in scope*" means that neither the Pilot, nor the 2019 scaled DR initiative, or this current Assignment have or will look into the implementation of this type of DR program

The **2019 nationwide DR events** were also designed on voluntary basis, with CLP and EDRP, and did not include any compensation.

The EVNHCMC DR pilot included a small sample of C/I customers in the Ho Chi Minh City area, while the 2019 nationwide program was on a nationwide initiative with a limited number of events.

For the non-dispatchable time-based DR Programs, a **Real-time Peak Load tariff** is planned and its feasibility will be examined in this Assignment.

In general, including and beyond 2020, the goal is that all DR program will be designed with a financial incentive.

4.2 EVNHCMC DR Pilot

4.2.1 Overview of the Pilot

In 2015, EVNHCMC ran 4 DR events, 2 CPL, and 2 EDRP events involving 9 commercial customers and 5 industrial ones. Total registered DR capacity for commercial customers totaled 5,022 kW which equated to 558 kW per customer; and 6 of the 9 commercial customers were hotels and the rest were commercial buildings. With respect to industrial customers, total registered DR capacity amounted to 830 kW, which equated to 166 kW per customer.

Positive demand reduction was achieved for all of the events ranging from 4% to 6% against the total baseline.

Although the pilot was a small sample, following a comprehensive assessment of the EVNHCMC 2015 pilot, whose results have been shared in an ERAV Report issued on 17/7/2017 Regarding the results of implementing the Pilot Load Adjustment Program, the country decided to go on to the next phase and scale up based on lessons learned in this initial phase.

4.2.2 Pilot Highlights Absence of Sustained Mechanism for Compensation

In particular, the above-cited ERAV Report highlights a key issue that arose related to incentive mechanisms and rebates. The report states in part:

> *"One of the most important objectives of the DSR pilot program is to test and evaluate the effectiveness of the supporting mechanism applied in the DSR pilot program.*
>
> *In order to develop a supporting mechanism to be applied in the DSR pilot program, ERAV has worked closely with the Department of Enterprise Finance (Ministry of Finance) to propose the application of the supporting mechanism to encourage which results in finance paid to participating customers will be forwarded and recovered via electricity retail prices.* ***However, the MOF does not***

> ***agree with the above mechanism, but only agrees to use EVNHCMC's Science and Technology Development Fund in the DSR pilot program.*** *This is also the reason the MOIT has temporarily approved the supporting mechanism to implement the DSR pilot programs at EVNHCMC, in which the supporting finance to customers participating in the DSR pilot program are from EVNHCMC's Science and Technology Development Fund.*
>
> *The supporting* ***mechanism applied in the pilot phase does not reflect the true nature of the supporting mechanism for DR programs that have been applied internationally.*** *In order to officially implement the DSR program nationwide, a complete and long-term financial mechanism is needed as a basis and motivation for Power Corporations/Power Companies to develop, declare implementation and attract customers.* ***[Emphasis added]***

While the approval of the financial mechanism for the Program is not under the authority of MOF, MOF has clarified several laws that were obstacles to the various long-term solutions proposed by MOIT/ERAV to the issue of financing mechanisms.

MOIT proposed that state-owned EVN be able to recoup the costs associated with DR programs through tariffs, and based on the compensation principle. MOF replied that for a mechanism that would accrue DR costs as operating expenses reflected in revenue requirements would not be appropriate, stating in part:

> *"Under the clause 2(k) Article 9 Decree No. 218/2013/ND-CP of Prime Minister dated 26/12/2013 on detailing and guiding the implementation of Enterprise Income Tax Law: "The expenses are not corresponding to the taxable revenues, with the exception of special cases complying with MOF guideline". The expenses must be deducted while calculating taxes, not record to the reasonable and valid expenses, as if regulating the tax-deductible when calculating enterprise income tax "not included in expenses". "*[21]

As for the compensation principle, MOF noted that they needed to review and ensure that this would be permissible under Article 7(1) and Article 8(8) Circular No. 219/2013/TT-BTC Guiding the Implementation of the Value Added Tax Law.

This was a contentious issue then, and remains on the table as MOIT and MOF are trying as we write to find a long-term solution to the financing mechanisms for DR programs.

In the short term, ERAV has worked closely with MOF to propose the application of an incentive mechanism to implement pilot programs for power load adjustment at EVNHCMC, in which the support fund for customers participating in the pilot program of power load adjustment are taken from the Science and Technology Development Fund of EVNHCMC.

[21] Appendix D

4.3 Year 2019 and Voluntary DR Events

Based on the outcomes of the EVNHCMC Pilot, and in line with Decision 175/QD-BCT on Approving the Implementation Plan and Roadmap for the DR Program which provides, among others, specific actions in Article 2 (a) for the 2019-2020 period, Vietnam did, on a national scale, roll out dispatchable DR in 2019, which we consider a trial year with valuable lessons.

The Consultant had the opportunity to ask stakeholders questions directly respecting the 2019 "dry run" year during its visit to Vietnam from February 9-14, 2020. We consulted with the parent EVN corporate team, 4 of the PCs, EVNHANOI, ENVCPC, EVNSPC, EVNHCMC. We include some of the feedback in this section, and more detail is provided at Appendix B.

Peak Demand Shifts and/or Demand Reductions Observed

In 2019, EVN carried out 10 DR events: 7 emergency DR events and 3 planned DR ones, on a voluntary non-commercial basis (i.e. without any compensation). According to EVN, the maximum capacity reduction was about 514 MW[22], about 53% of the projected DR potential reduction (see table below) for a total electricity reduction around 6,373 MWh, and estimated saving equal to VND 24.12 billion (amount equivalent to not running certain oil-fired power plants).

During consultations, EVNHANOI, whose 2019 DR report is included at Appendix C, mentioned that the DR events did not correspond to their peak times.

Level of Participation

As highlighted in the table and figures below, all distributors ran marketing campaigns to reach their key customers and sign them up for the CLP and EDRP programs. They have done so with relatively good success considering there were no financial incentives involved. This is very promising for future programming periods, as the level of participation should only go up from this initial participation level when financial incentives are put in place.

Table 4-2: Potential for Non-commercial DR Implementation in 2019 (figures as at 31 May 2019)

	Total Number of Key Customers	**Total Number of Customers Reached**	**Total Number of Customers Signed (% of total key customers)**	**Total Reduction Potential (MW)**
EVNNPC	1,607	1,490	913 (57%)	257
EVNCPC	249	249	119 (48%)	113
EVNSPC	1,760	1,760	875 (50%)	414
EVNHANOI	225	225	147 (65%)	53
EVNHCMC	573	573	317 (55%)	126
EVN	**4,414**	**4,297**	**2,471 (56%)**	**963**

Source: EVN

[22] (September 10, 2019).

Figure 4-1: Number of targeted and participating customers

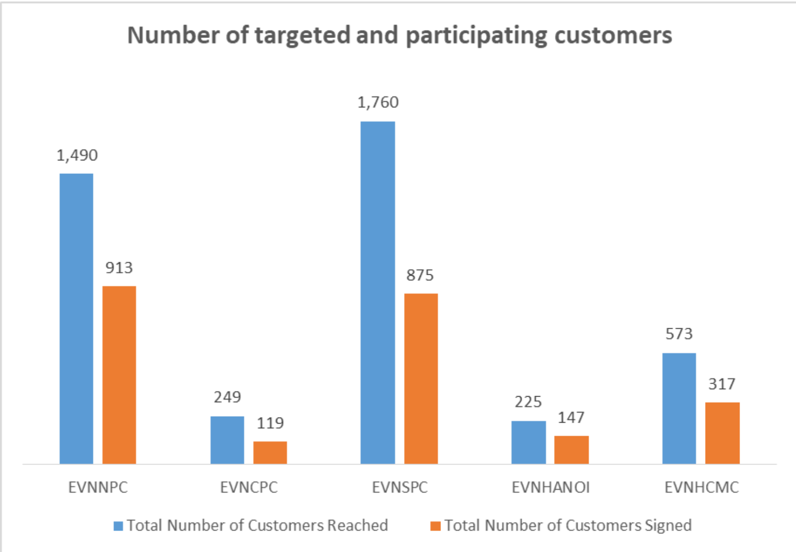


Figure 4-2: Proportion of participating customers

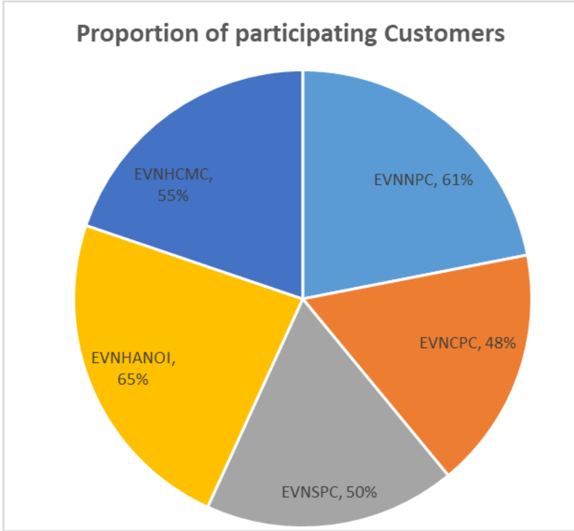


Figure 4-3: Number of key customers and potential reductions

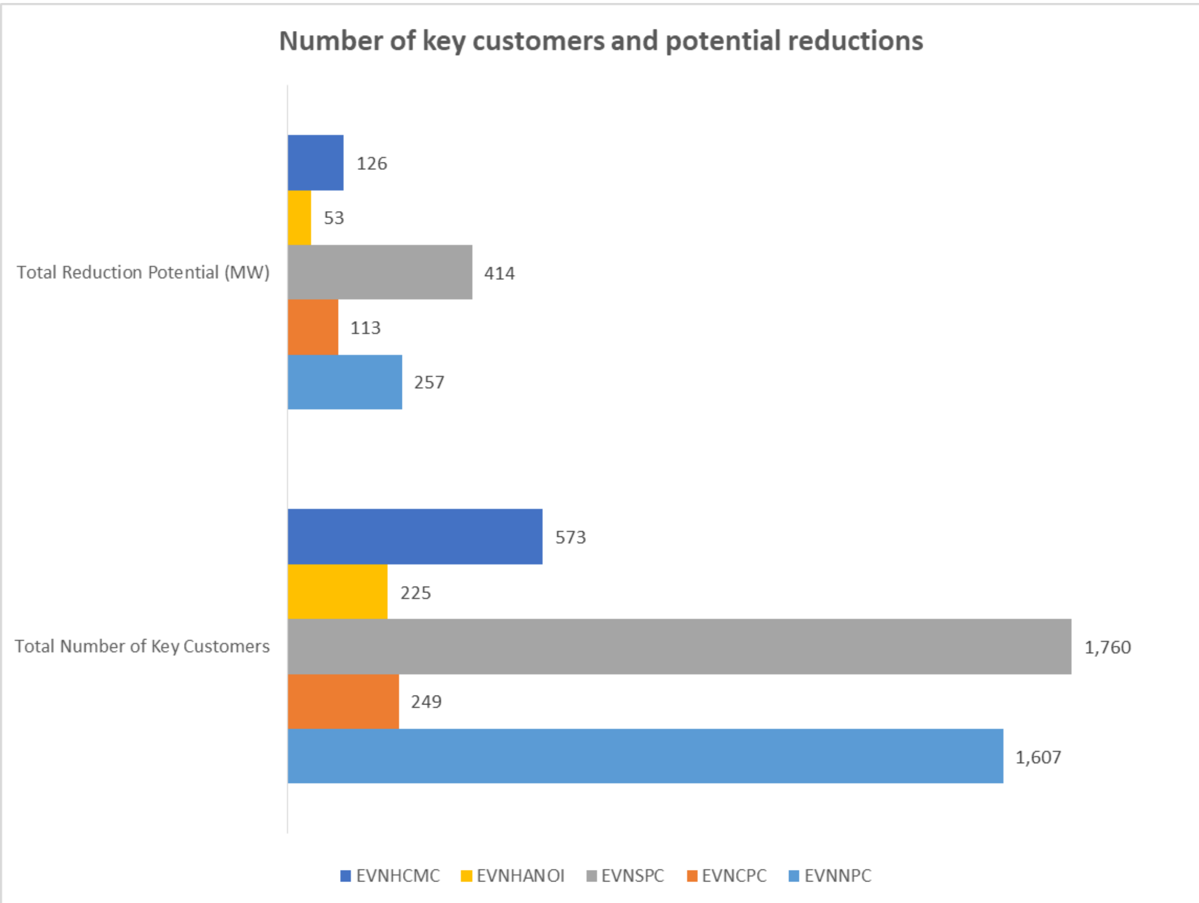


Figure 4-4: Proportion of reduction potential

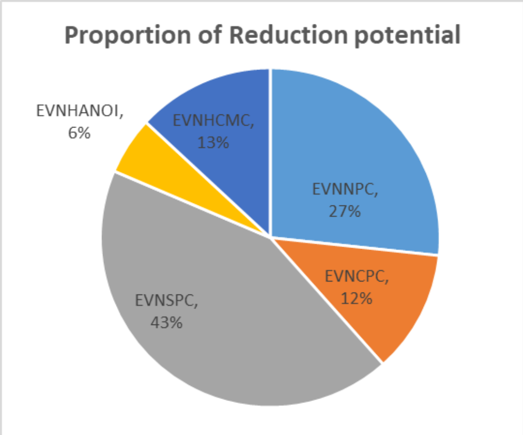
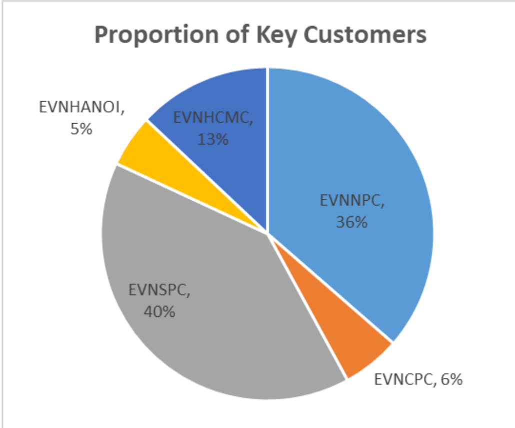


Figure 4-5: Proportion of key customers



During consultations, all stakeholders on the EVN side noted with respect to participation levels that DR programs are voluntary, so marketing them to potential participants is difficult.

They also commented on the lack of compensation, and how this missing component negatively impacts participation levels and could potentially jeopardize the success of the program in the long run as DR events augment as per government plan.

Demand Response Baseline

For dispatchable DR programs, a baseline is an estimate of the electricity that would have been consumed by the end-user in the absence of a demand response event.
The Consultant understands that the baseline of the DR event of each customer will be calculated by PCs who have signed a PPA with these customers, against which actual metered use will be compared.

Load Reduction = Baseline – Actual Metered Use

The setting of the baseline will serve as the primary tool for measurement for incentive payments to the customer who participated in the program. For 2019, detail regarding the setting of the baselines has not been shared with the Consultant.

Establishing the baseline load profile is essential to later measure and verify the impact of DR. Measurement and verification was not an aspect that stakeholders could tell us much about, was what recurrent was the fact that the system planner and operator NLDC was not sharing much detail, and that this situation was less than ideal for distributors in charge in essence of these DR events. This is a gap that we have identified and needs to be addressed, namely communication between NLDC and distributors regarding load profile baseline estimates should be shared and how each distributor is allocated a projected load reduction.

Challenge: Level of Compensation and Incentive Mechanism

Utilities are expected to provide reliable electric service at least cost. With respect to DR resources, this means that utilities should be willing to pay up to their avoided costs to acquire equivalent services from DR. In determining the level of compensation, key questions should be answered:

- What is the targeted load shifting worth to the system?
    - Capacity = cost of peaking plant (if the system needs additional capacity)
    - Energy = peak energy price (if the resource is available at peak times)
    - Possibly avoided externalities, such as avoided emissions.
- Will consumers participate at that price?
- Is participation sufficient to warrant a program?
- Who pays for implementation costs?/ How can utilities recover the cost of implementation of DR.

During consultations, the issue related to compensation for participation in DR programs was a recurrent one, and all parties agreed that this was a major obstacle to sustained DR programming.

All aspects surrounding incentive payments, including the method for calculating the baseline, have not been fully explored in 2019 by EVN entities as there are legislative issues outside of EVN's control, and for that matter outside of the control of the Ministry it falls under (MOIT), that impeded the development of financial incentives. We will revisit more in depth these issues later in the report.

<u>A plus: Technological Readiness</u>

The Demand Response Management System (DRMS), a tool that has been developed internally at EVN, was also tested in 2019. Most of the DRMS functionalities are ready, and the software has successfully been operated during event.

There was consensus from stakeholders during consultations that the new DR software tool works well. However, one PC noted that it was missing a major functionality, namely the cost/pricing one, so utilities can't actually see in real time the peak load profile and peak pricing for the system, or their service area. Again, NLDC was brought into the conversation, and stakeholders hoped for higher transparency from the system operator.

<u>Beyond 2019</u>

The next phase, namely year 2020 has 11 planned DR events (up from 3), for a projected reduction equal to 90 MW per event. Beyond that, EVN stated that the goal is to bank on DR to reduce demand by 6,000-8,000 MW per year, in accordance with Decision 175 (the Road Map)[23].

[23] Decision 175: targets per DR event correspond to at least 90 MW by 2020, 300 MW by 2025 and 600 MW by 2030

4.4 Planned Demand Response in 2020

On December 27, 2019, responding to a request from its parent company EVN, the national system operator NLDC sent a letter[24] outlining the capacity and timeline for 11 DR events spread on a monthly basis in 2020. The schedule for DR distinguishes between the three geographical zones, North, Central and South, in which DR planned capacity ranges respectively from 353-736 MW; 68-150 MW; and 340-785 MW. While in the Central and Southern regions a single period stretching 3 hours is planned, for the North, summer months, June to August, will see two separate DR events, the first for one hour, the second stretching 2 hours, for a total of 3 hours on the event day.

In regard of the balance between the supply and expected demand established by AO, January 7, 2020, EVN published 88/EVN-KD document to inform the power corporations of the voluntary and non-commercial DR program implementation plan in 2020, in which includes the allocation of DR capacity to each power corporation. The expected months to implement the program are last from February to August, 2020. EVN will give detailed inform on the date to implement DR events at the beginning of each month. However, in 2020, due to COVID-19 pandemic and to avoid the impacts on the business activities of customers, EVN has stopped doing DR program as planned"

[24] Letter 4762/DDQG-DD

Chapter 05

Remaining Barriers to Implementation

5 Remaining Barriers to Implementation

5.1 Jurisdictional Barriers

5.1.1 Pivotal Role of the Ministry of Finance

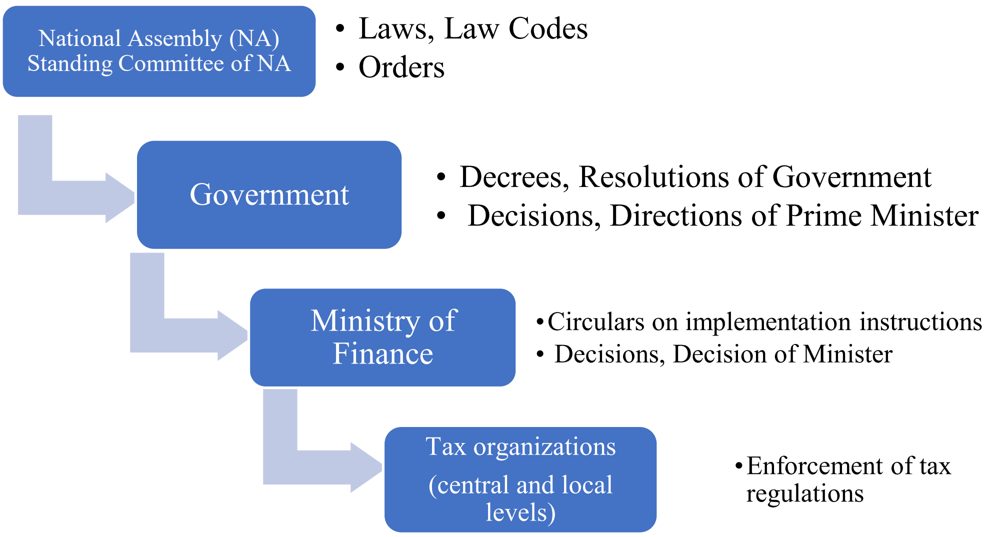
EVN is a State-owned enterprise and Financial management at EVN must comply with the Law on management and utilization of state capital invested in the enterprise's manufacturing and business activities No. 69/2014/QH13, the Government's Decree No. 10/2017/ND-CP dated 09/2/2017, Decree No. 91/2015/ND-CP dated October 13, 2015 and Decree No. 32/2018/ND-CP dated March 8, 2018. Additionally, the operation and implementation of EVN's activities are regulated under Decree No 26/2018/ND-CP dated 28/2/2018 on the organization and operation charter of Vietnam electricity and Decree No 10/2017/ND-CP dated 9/2/2017 promulgating the regulation on financial management of Vietnam electricity. The Government, Ministry of Finance and other agencies are regulated under these documents, following:

> *Article 5 (Decree 10/2019/ND-CP): Implementation of rights and responsibilities of the government*
> *1. The Committee for management of state capital at enterprises shall have the right to request competent regulatory authorities to appeal to the government to: Promulgate, amend and supplement the statutes of wholly state-owned enterprises that are established under the Prime Minister's decision and of which management is authorized to the committee in accordance with the Government's regulations; promulgate, amend and supplement financial management regulations of the Vietnam National oil and Gas group, and the Vietnam Electricity Group.*
> *3. The Ministry of Finance:*
> *a) Appeal to the government to promulgate: Regulations on transformation of wholly state-owned enterprise into joint-stock companies; regulations on financial administration of wholly state-owned enterprises; regulations on criteria assessment of business performance and efficiency of wholly state-owned enterprises; regulations on supervision and inspection of investment, management and use of state capital at enterprises;*
> *b) Prepare the report on investment, management and use of state capital at enterprises nationwide for submission to the Government so that the Government may review it and present it in the year-end meeting of the National Assembly under its authority delegated by the government.*

Thus, the authority to promulgate, amend and supplement the financial management mechanism of EVN is at the Government level. The MOF plays a role as the government body that prepares the proposal, reports, legal draft submitted to the Government following the legal procedure (Law No 80/2015/QH13). Furthermore, under the clause 1 Article 5 Decree 10/2019/ND-CP, it is suggested that the Ministry of Industry and Trade coordinates with The Commission for the Management of state capital at enterprises (CMSC) to study and clarify the legal basis, and propose the necessary amendments and supplements EVN's financial management regulations. Based on that CMSC will be in the leading role to request relevant authorities to submit the proposal to the Government for review, consideration and decision-making.

Beside the Decree 10, there are several laws and regulations which have an impact on the financial aspect of implementation of DR program, such as price law, Corporation Income tax law and guideline documents. While all legislation in Vietnam must comply with the constitution, as part of the legal system and under various institution's regulations, different authorities have specific powers to issue or revise certain legislations. The figure below shows the different institutions involved in deciding on, and implementing, different type of tax policies.

Figure 5-1: Institutions involved in decision-making and implementing tax policies



While revision of the Corporate Income tax law and other tax law (in general, of all laws) will require the National Assembly's approval, the Ministry of Finance has the responsibility to provide detailed guidance on the governing and implementation of the taxations, including on tax rates and level of charges and fees. Therefore, to establish and implement DR programs, a number of Laws and decrees that are required to review carefully. MOIT (in collaboration with EVN), and the committee should have the reports and proposal to submit to the right level of authority under the Vietnam's legislations. MOF, when requested by the Government or by MOIT, is the agency that can collaborate with MOIT to review all the relative legal documents and provide feedback within its legal jurisdiction following its responsibilities.

Guided by Decree 10, EVN and its subsidiaries have to abide, for accounting purposes, by the prescribed accounting rules for state-owned entities. There appears to be an inadequacy regarding the recording of demand response related expenses in operating expenditures for EVN and its subsidiaries. These issues were highlighted in writing in communications between MOF and MOIT, most recently through MOF's letter dated 23

April 2020, responding to MOIT/ERAV's Letter 10192 /BCT-TKNL dated 31 December 2019.

The Ministry of Finance also plays a role in respect of electricity tariffs as outlined in the Prime Minister Decision 28/2014/QD-TTg of April 2014 on Regulations on Structure of Electricity Retail Tariff. In particular, Article 5, paragraph 3 of this Decision states in part:

> ***Article 5. Implementing Organization***
> *3. The Ministry of Finance shall:*
>
> *a) **Assume the prime responsibility** and coordinate with the Ministry of Industry and Trade, Ministry of Labor - Invalids and Social Affairs to **calculate the annual support for** the poor households and social policy households under the provisions in Clause 6, Clause 7 and Clause 8, Article 3 of this Decision for submission to the Prime Minister for consideration and decision;*
> *b) **Assume the prime responsibility** and coordinate with the Ministry of Industry and Trade, Ministry of Labor - Invalids and Social Affairs to **guide, inspect and supervise the support of electricity cost** for the poor households and social policy households; [**Emphasis added**]*

Article 5 of the Decision identifies four government entities with varying degrees of responsibilities in the tariff setting process, namely the Ministry of Industry and Trade, the Ministry of Finance, the Ministry of Labour and Social Services, and provincial People's Committees. While the role of the latter two agencies is more of an advisory one, the duties of MOF clearly deal with cost input. To implement this policy, MOF issued Circular 190/2014/TT-BTC dated 11/12/2014 on promulgate the implementation of support for the poor households and social policy households and the funds for supporting the electricity cost for the poor households and social policy households are deducted from state budget and local budgets.

In section 2.3.1 Tariffs, we mentioned that while the redistribution of revenues is not a standard purpose of regulated tariffs, they can be designed as a welfare support tool, case in point here. We also mentioned that in a competitive electricity market, tariffs function to maintain financial sustainability of the firms involved and promote the efficient use of electricity.

TOU tariff has been included in existing tariff structure which slightly supports the implementation of DR events. However, the difference between tariff for peak hours and tariff for off-peak hours is not significant enough to promote economic DR implementation.

5.1.2 Current State

Based on the EVNHCMC Pilot experience for which MOIT/ERAV's demand response proposed incentive mechanism is not allowed by the legislation structure and another financing solution had to be devised. The EVNHCMC Pilot experience also highlights the cooperation between the two ministries.

Furthermore, as shown in the various communication between the two ministries, in particular Letter 10192 /BCT-TKNL from MOIT to MOF dated 31/12/2019 containing Comments on the Development of an Energy Service Market and Demand-side Management, is that an enabling legal framework is necessary in order to derive the monetary value of demand response and generate the appropriate incentive mechanisms to induce and maintain a certain level of participation in the targeted demand response programs.

For the national demand response roll-out, stakeholder consultations[25] we conducted reinforce the above noted elements.

The meeting with MOF specifically focused on Letter 10192 of 31/12/2019. The letter is an open invitation to MOF to answer and resolve the issue of the design of DR financial mechanisms which is the last standing major implementation hurdle to full scale national rollout. We met with the Department of Corporate Finance. We noted the absence of the Department of Accounting, which may have shed further light on the issues on the table that relate to regulatory accounting and cost recovery through tariffs. Elements contained in the letter are addressed later in the text.

Some of the key elements raised by MOIT in its latest letter to MOF:

- → Only one of the DR programs in Circular 23 is currently actionable, namely the DR program based on non-commercial mechanism. DR programs based on direct incentives and tariff designs cannot be implemented due to the lack of financial mechanism and new electricity tariff.
- → MOIT recalled the forms of commercial incentives that may be available to current C/I consumers:
    - Direct incentives offered based on the participant's reduced consumption
    - Dynamic pricing incentives, building on current TOU tariffs to include Real Time Pricing or Critical Peak Pricing.
- → On boosting participation levels and ensuring the sustainability of the program, MOIT highlighted that commercial incentives are conclusive in attracting customers to participate in the program for the long term, however non-commercial incentives are not a lasting solution.
- → The estimated cost for direct financial incentive for customers in the DR program for period 2020-2030 would be about 609.7 billion VND according to EVN, which is equivalent to 55.5 billion VND/year.
- → Decision 279 asks MOIT to offer and harmonize compensation mechanisms to encourage customers' participation, and think about operating expenses of EVN PCs
- → Proposals / Suggestions: MOIT suggested that DSM/DR implementation costs be recognized as eligible cost and accounted for as operation cost, then recovered through retail electric tariff.

[25] Appendix B

On 27 March 2020, MOF provided its reply in Letter 3609/BTC-TCDN titled Comments on Some Issues Related to the Development of the Energy Service Market and Demand-side Management ("Letter 3609").

Letter 3609 addresses two main issues, **the micro policy matter related to the regulatory accounting issue respecting the recognition and classification of DR expenses, and a macro matter related to financial solutions that the market, expressly energy services companies (ESCOs) may offer to implement the nationwide DR programs.**

As regards the regulatory treatment of DR related costs, MOIT's proposal that incentives expensed to compensate DR program participants be considered as reasonable costs and as such be included into the "production and business cost", and recoverable through rates, MOF reaffirmed that the Law on Corporate Income tax does not offer a finite answer and there may be some wiggle room in the legal provisions to help the regulator adopt a financing mechanism through tariffs as is the case in most jurisdictions with deep DR experience. For completion, with respect to the Law on Corporate Income Tax, MOF's reply stated:

> According to the Law on Corporate Income Tax (CIT), enterprise shall not count the expenses that are not corresponding to taxable income as deductible expenses (point k, clause 2 Article 9 of Decree No. 218/2013/ND-CP of the Government).

MOF observed that there may be two avenues to finance DR incentives. One route would use the same mechanism as applied during the EVNHCMC pilot leveraging provisions under the Law on Scientific and Technological Development. The second route relates to the definition of what is considered a direct expense under the Law on Corporate Income Tax, it may take longer to adopt but may be more appropriate if lasting effects are considered and predictability favoured. A direct expense[26] is cost recoverable. MOF notes that direct expenses are those that relate to electricity production and business activities such as electricity generation, transmission or distribution. There is a large amount of material written on whether to consider demand response as "negative generation" in its role as supply insurance. While some scholars argue in favour of the "negawatts" DR brings to the system, others do not support defining and valuing DR that way. Regardless, MOIT can certainly argue the case for considering DR's "negative generation" as a direct expense like "positive generation". MOF noted however that it does not make that call and has referred MOIT to other government institutions.

Additionally, in MOF's reply letter, MOF also reminded the regulations on financial management of Vietnam electricity group (EVN) attached to Decree No 10/2017/ND-CP dated 09/02/2017 (Clause 5 Article 25 and clause 1 Article 26). Hence, EVN determines the deductible expenses for calculating taxable income under the law and must strictly manage its expenses to ensure that those costs are reasonable and valid under the

[26] MOF's Letter 3609/BTC-TCDN states: "As such, it is necessary to study and consider the incentive for consumers who participate in the DSM/DR programs under the CIT Law and other legal provisions, with directions as follows:

- If they are direct expenses related to electricity production and business activities (electricity generation, transmission or distribution) and has fully invoices and evidence, they are included in deductible expenses when determining taxable income under the CIT law and its regulations.
- If these expense are associated with scientific research programs under the Law on Scientific and Technological Development, they should be used from the scientific and technological fund in compliance with regulations."

taxation laws and regulations. The costs related to production and business activities in the fiscal year, consist of: cost for production and business (taxes, fees and other charges under the law); expenses of financial activities (financial investment, interest paid, exchange rate differences, payment discount costs, asset leasing expenses) and other costs. Therefore, to support the DR programs, it is important to determine this expense or the incentive finance in the EVN's financial management mechanism.

According to Clause 1 Article 5 Decree No 10/2019/ND-CP, MOF suggested that the MOIT coordinates with the Commission for the Management of state capital at enterprises to study and clarify the legal basis, and propose the necessary amendments and supplements the EVN's financial management mechanism.

Based on MOF's reply letter, we understand that there may be scope for modifying or specifying the Law on Corporate Income Tax to define DR expenses as direct expenses so that there are eligible for cost recovery through tariffs. While this is the solution that offers the clearest path for expensing DR incentives and financing a nationwide program, realistically this may take a number of months, possibly years, while the need for implementation of the nationwide government mandated DR is under way. While energy efficiency is the DSM cousin to DR, and many of the principles applicable to one are transferrable to the other, and while we recognize that EE is largely driven by permanent measures and DR by periodic events, with incentive mechanism issues in EE much less complex than in the context of DR, since Vietnam is currently also implementing energy efficiency initiatives, the Consultant believes it useful to examine funding mechanisms and financing models in the context of energy efficiency to help explore the appropriate solution for financing DR in Vietnam.

5.2 Tariff Structure and Cost Allocation

While the financial mechanism concerns the incentive-based programs, Curtailable Load and Emergency DR, the third program that this Assignment is looking into, the peak-load tariff, has to do with tariffs, and possibly reflecting this new tariff in Vietnam's TOU structure.

Demand response programs are being implemented as a cost-effective alternative to undertaking major capital investments in generation and grid infrastructure. Consequently, it is appropriate to recover the costs incurred for the DR program (i.e., incentives plus administrative/marketing/other costs) in the same manner as costs associated with increased capacity in the absence of the DR program.

As noted earlier in the report, in most jurisdictions, costs are allocated to customers on the basis of the cost causality principle. This method involves allocating costs to customer classes based on the coincident peak demand of each customer class. Adopting this approach ensures that all customer classes bear lower costs (and pay lower tariffs) than they would if investments were made to increase system capacity, rather than implementing the DR program in order to avoid the higher cost of the additional infrastructure. We need to understand who currently contributes to peaks. Keeping with the cost causality principle, cost is recovered based on who benefits most from the saved infrastructure costs. We need to clarify the cost allocation model. In the absence of a cost allocation model, we may not know who actually pays for peak capacity.

Although we have highlighted issues related to the cost allocation model, the peak-load tariff DR program should be feasible provided that compliance with the requirement to reduce consumption is assured either because:

- → The distributors are able to cut off power to participating customers (depends on smart grid technology with 2-way communication and centralized control of customer use) so that the intended reduction in demand actually occurs (otherwise requests for reductions will have to exceed the requirement based on expected compliance); or
- → Penalties for non-compliance (price of unauthorized overruns) are high enough to ensure that there will be a high degree of compliance.

Otherwise, "Critical Peak Pricing (CPP)" is an alternative to the peak-load tariff DR that relies on an extremely high price rather than voluntary or mandated demand reductions to reduce demand at "critical peak periods". Critical peak periods are times when production costs (or imports) are prohibitively expensive or unavailable. It aims to reduce load during the relatively few, very expensive hours more dynamically. In CPP tariff design, the important elements are the time window over the peak price period and the degree of price differentiations between the peak and off peak times.

5.3 Baseline Load Profile and Measurement and Verification (M&V)

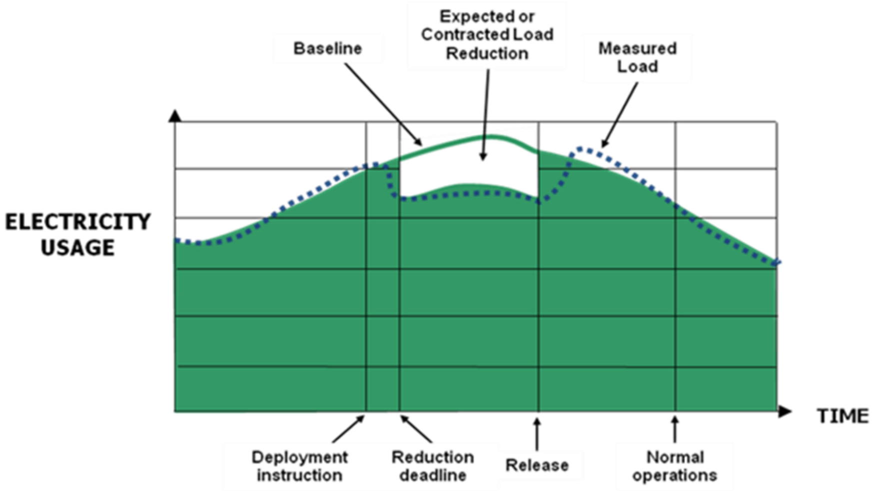
The DR baseline is an estimate of the electricity that would have been consumed by an end user in the absence of a demand response event. The baseline is compared to the actual metered electricity consumption during the DR event to determine the demand reduction value.

DR performance relies and depends on the baseline calculations which means that the methodology for this calculation needs to be as accurate as possible.

- → Two techniques for calculating baselines are day matching and regression analysis[27]. Day matching is the most commonly used.
- → Day matching involves constructing a baseline day that most accurately matches the actual DR event day.
- → The <u>baseline will serve as the primary tool for measurement that forms the basis for incentive payments to the participating customer</u>.

The figure below illustrates the concept of baseline in the context of a DR event.

[27] Regression based baselines are more accurate, but are also more vulnerable to manipulation



Source: NAESB

While baselines determine the value of curtailment, and are the basis for compensation for participants, what we have heard is that the system operator NLDC is not sharing much information with PCs with regards to load profiles. Decision 54 does address baseline calculations, but it's not clear how manipulation will be avoided. We identify this as a gap.

In addition, an effective DR program requires the ability to measure and verify the impact of each participant, i.e. the ability to calculate the shift in demand associated with the end-user during the DR event as compared to the baseline load profile. Solid measurement and verification protocols are necessary, the first quantifies the change, and the second validates the measured change.

While the first is addressed in Decision 54, verification protocols have not been emphasized as compensation seems to have dwarfed other essential issues. We bring this to the attention of the client and the need to ensure that M&V protocols are in place, clear, and not prone to manipulation.

5.4 Conclusion

At the beginning of this report, we asked some key questions which we briefly recap in this section.

1. Is DR an appropriate answer to the challenges facing Vietnam's power sector?
2. Is there a clear policy, strategy and implementation program regarding DR?
3. Is the existing institutional and regulatory framework appropriate to implement the program?
4. Is the feedback from the 2019 rollout encouraging as regards further implementation of DR?
5. What are the remaining barriers to successful implementation of DR?

Based on the supply and demand fundamentals we studied, the use of demand response seems more like a must rather than an option. We will highlight that the structure of tariffs and cost allocation to the industrial customer class may be a hurdle to the implementation of peak-load tariff DR, however it is feasible.

Vietnam is gradually phasing in DR, with each phase seeing legislative and regulatory instruments to accompany the various steps. The latest instrument, Decision 54 speaks to the level of readiness of the country. Appropriate checks and balances are in place, with several government actors involved. Two regulatory instruments are lacking, the first which we have addressed at various points and which is also top of mind for policy makers at ERAV, deals with compensation of participants and the design of incentive mechanisms associated with DR programs, while the second deals with the protocols and NLDC communication with PCs for the calculations of baseline load profiles and verification.

Operationally, the overall feedback regarding the 2019 rollout in encouraging, especially as regards the readiness of the DRMS software and the hardware on the participating consumer's end.

In the next section of this report, we will look at international experiences to implement DR programs in the C/I segment for CLP, EDRP, and peak-load tariff, with a focus on the gaps identified in this report, namely on compensation mechanisms involved in the various international models, and M&V protocols.

PART II:

RELEVANT INTERNATIONAL BEST PRACTICES IN DR PROGRAM IMPLEMENTATION

Chapter

06

Introduction

6 Introduction

The purpose of Part II: Relevant international best practices is to provide relevant proven international best practices related to DR program implementation, including an analysis and a compilation of internationally proven regulations supporting the deployment of DR programs (applicable to Vietnam), e.g. the incentive mechanism, etc. in order to later on recommend further relevant improvements with the purpose of enabling implementation of the DR programs (including all sub-programs) outlined in Circular 23/2017/TT-BCT.

In order to focus the scope of the research and available resources, the selection of jurisdictions for the international review were chosen using a priority matrix rather than a simple region-by-region summary. Therefore, the DR programs selected for review for this report were limited to successful examples, regional programs of note, or those that share similarities with piloted programs, as further explained in Chapter 2. Some of the included jurisdictions, such as California, offer a wider range of DR options than programs currently under consideration by ERAV, including programs for residential customers.

This section intends to answer the following questions:

6. What are the most relevant jurisdictions?
7. What characterizes the success of those initiatives?
8. What are the important lessons learned for Vietnam?
9. What are the financing mechanisms used in these shortlisted jurisdictions?
10. What are the baseline and measurement and evaluation methodologies in use in these jurisdictions?

Chapter 07

International Experience in CLP, EDRP, and Peak-load Tariff DR Programs

7 International Experience in CLP, EDRP, and Peak-load Tariff DR Programs

7.1 Rationale for the Short List of Jurisdictions Selected

- The Curtailable Load program;
- The Emergency Demand Response program; and
- The Real-time Peak Load Electricity-tariff program.

The shortlisted jurisdictions all have programs that can be seen as more or less similar to those programs that have been piloted in Vietnam or are being considered. Some, like Australia, have programs that appear to be very similar to those considered, yet the Vietnamese programs are in a less advanced state. Although California is a jurisdiction that has many differences from Vietnam, its programs are very similar to all the three programs considered by Vietnam, and have a fairly high level of maturity.

Table 7-1: Shortlisted jurisdictions and their similarity to programs considered in Vietnam

	CLP	EDRP	PLT-DR
South Korea			x
California	x	x	x
Japan	x	x	
Singapore	x		x
Australia	x	x	x

7.1.1 Long List of Jurisdictions and Organizations for Further Study

A long list of jurisdictions considered was created based on the professional experience of the Consultant's team members and a survey of relevant literature. Twelve jurisdictions and organizations were chosen. The team performed desk research to gather key statistics and information about each and assessed the availability and accessibility of information. The long list of jurisdictions and organisations includes:

- South Korea
- California
- Japan
- Singapore
- Australia
- Thailand
- PJM[28]
- Hydro Québec
- Pacific Northwest
- Ontario
- Seattle City Light
- Texas

Note that the EU was considered for the long list above, but was not included due to the fact that DR programs in the EU are still in the nascent stages with inconsistent

[28] PJM is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia, in the United States of America.

application across member states (e.g. Italy and Spain currently do not allow aggregation), and therefore its market as a whole is not as mature as those selected for further study.[29]

7.1.2 Shortlisted Jurisdictions and Rationale for the Selection

The above jurisdictions and organisations were evaluated using a multi-criterion evaluation model. The criteria were selected and each jurisdiction was evaluated using a scoring system. The criteria were subjective and based on professional judgement and available research findings. Those programs similar to the three programs considered by Vietnam each earned one point. Overall similarity to Vietnam (in terms of electricity demands and market conditions), regional presence, climate similarity and maturity of experience in each jurisdiction were all evaluated against the multi-criterion matrix. The jurisdictions and organisations with the highest scores were put on the shortlist. The selection matrix is shown in Table 7-2 below.

Table 7-2: Selection Matrix – Shortlisted Countries Highlighted in Bold Letters

	CLP	EDRP	PLT-DR	Similarity to Vietnam	Neighbouring to Vietnam (Regional)	Climate Similarity	Maturity of Experience
South Korea			**x**	**some**	**yes**	**some**	**medium**
California	**x**	**x**	**x**	**some**	**no**	**some**	**high**
Japan	**x**	**x**		**some**	**yes**	**some**	**medium**
Singapore	**x**		**x**	**some**	**yes**	**some**	**medium**
Australia	**x**	**x**	**x**	**some**	**yes**	**some**	**medium**
Thailand				some	yes	some	low
PJM			x	not very	no	no	low
Hydro Québec	x	x	x	not very	no	no	high
Pacific Northwest	X		x	not very	no	no	high
Ontario		x		not very	no	no	medium
Seattle City Light	x			low	no	no	low
Texas	x	x	x	low	no	little	medium

This first subsection has answered the question of "What are the most relevant jurisdictions" from which Vietnam may find inspirations for its DR programs.

In the following country-by-country examination, two questions will be answered: What characterizes the success of those initiatives? What are the important lessons learned that can be relevant for Vietnam? For each jurisdiction, the report provides details on the programs, the entities responsible for implementation, funding mechanisms, and baseline calculation and evaluation methodologies. The chapters also cover relevant key success factors or lessons learned from DR program implementation, where appropriate.

[29] *Why Demand Response is not implemented in the EU? Status of Demand Response and recommendations to allow Demand Response to be fully integrated in Energy Markets.* By Paolo Bertoldi, Paolo Zancanella, and Benigna Boza Kiss, EU Joint Research Centre, 2017.

It should be noted that this study presents the balance between a simple international survey of key, established DR programs, and deep analysis of those DR programs that have some relation to Vietnam's programs and conditions. This approach was chosen because a survey would only identify the regions and programs, and would be useful before the implementation of any pilot DR programs, while a case study would be more appropriate once the key program elements have been identified for Vietnam, allowing the case study to further cover each program element in depth.

7.2 South Korea

South Korea is a country in East Asia. Situated on the southern half of the Korean Peninsula, it covers a total area of more than 100,000 square kilometres. Its population is estimated at around 50.8 million and the country is noted for its population density, which is more than 10 times the global average. South Korea has one of the largest economies in the world, with per capita income of more than USD 30,000 in 2018.[30]

7.2.1 Background

South Korea's geography and political situation mean that it operates as an island in terms of electricity supply. Its energy security has always been a major concern to the government. Currently, nearly 80% of the demand is from commercial and industrial energy users.

Liberalization of the electricity market was started in 1999 but halted in 2003 after only the power generation segment had been liberalized. As a result, there is limited competition is in the generation segment; transmission, distribution and retail continue to be handled by the Korea Electric Power Corporation (KEPCO). The Korea Power Exchange (KPX) was established in 2000 and all the power-generating businesses are obliged to sell electricity to KEPCO through KPX. KPX makes demand forecasts and receives day-ahead proposals from generating companies, which it uses to set the system marginal price (SMP) for each trading hour, effectively forming the market price. Capacity payments are made to generating companies based on their bids.

Large consumers can purchase power directly on the wholesale market, whereas smaller consumers have regulated tariffs in place. The tariffs are intended to allow KEPCO to recover costs and provide an appropriate return on investment. Industrial tariffs have nearly doubled in the past 15 years but still have some of the lowest tariff classes available at about EUR 0.08/kWh. This low pricing limits the incentive for industrial consumers to voluntarily participate in demand response.[31]

The Korean DR market was first opened in 2008, and was transformed in 2015 in order to more closely integrate the program into the Korean electricity market, where it is currently operates. Many technologies and business models have seen rapid progress in Korea. The demand response (DR) market has taken off since a regulation was adopted

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[30] Statista 2019 https://de.statista.com/statistik/daten/studie/14440/umfrage/bruttoinlandsprodukt-pro-kopf-insuedkorea/

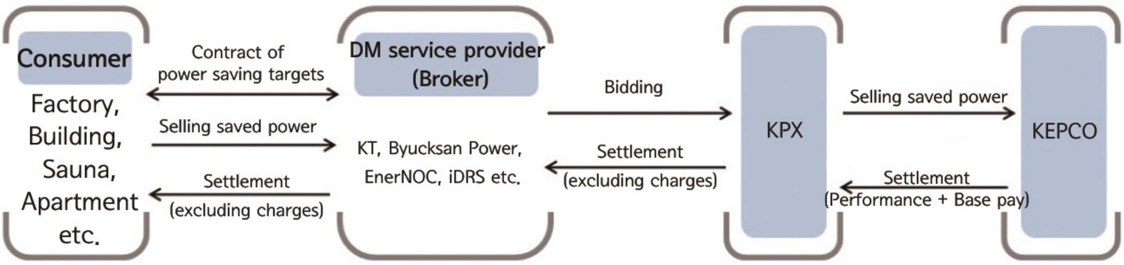
[31] Jensterle, M. et al. "System integration of renewables and smart grids in Korea" Wuppertal Institute, 2019.

in 2014[32]. South Korea is actively promoting DR to help ensure reliability, encourage competition, and develop an ecosystem of IT-based energy businesses[33].

7.2.2 Programs and Experience

The South Korean DR market is known as the “Negawatt” market. The market generates profits by collecting and selling the electricity saved by residential, commercial and industrial consumers. A load aggregator sells the saved electricity by tendering in the electricity market, competing in prices with generating companies. Each demand resource is required to come from at least 10 end-users and must be valued at above 10 MW. Load aggregators operate under a contract with KPX, and then control the electricity demand of customers according to the reduction instructions from KPX. After a transaction, the load aggregator is paid by KPX for the electricity it sold and pays the settlement money to the aggregator according to the amount the consumer saved. DR resources are put on a bid against power generation resources on a daily basis and when sold, demand curtailment begins. A general transaction flow is shown in Figure 7-1 below.

Figure 7-1: Negawatt Transaction Flow[34]



The market is divided into a “reliability-based demand response market” and an “economic-feasibility-based demand response market” where consumers participate in the bidding voluntarily. The reliability-based DR (peak-shaving DR) should follow a reduction instruction by KPX within 1 hour before the power supply and demand is at risk. It aims to improve the reliability of electrical systems, playing a role to lower maximum power and dealing with volatile power supply and demand. The economic-feasibility-based demand response (cost reduction DR) enables consumers to participate in the bidding voluntarily when a reduction unit price of demand resource is thought to be lower than a generation unit price. These are summarized in Table 7-3 below.[35]

Table 7-3: DR summary South Korea

Category	Reliability	Economic
Program Period	Bidding (Twice/year)	Day Ahead bidding
Notification Time	1 hour ahead	Day ahead

32 “Is the Asia-Pacific Region Demand Response Ready?” Frost & Sullivan, July 2018 https://ww2.frost.com/frost-perspectives/asia-pacific-region-demand-response-ready/
33 “Demand Response Status and Initiatives Around the World” Global Smart Grid Federation, Nov. 2016. http://globalsmartgridfederation.org/dashboard/uploads/BDAfr1513318888.pdf
34 Lee, C. “The Negawatt Era is Coming”. *Green Focus*, Vol. 7, 2015. Available at https://www.gtck.re.kr/frt/center/en/tech/green_focus.do?pageMode=View&nttId=22279
35 Navigant. “Demand Response Discussion Paper Utilization Payments”, prepared for the IESO, 2017.

Payment	Capacity* + Variable cost of Marginal Gen	System marginal price**

**Capacity payment in first 6 months of 2017: 19,894.7 won/kW (approx. USD 16/kW)*
***Average SMP in first 6 months of 2017: 84.36 won/kWh (USD 0.069/kWh)*

The "Negawatt" market has grown substantially since 2014 when consumers became able to offer their demand-response capacities on the market through aggregators. Data from 2018 indicates more than 3,500 consumers, over 20 aggregators and over 120,000 MWh curtailed in only part of the year. The total current demand-response capacity stands at about 4.3GW.[36]

7.2.3 Some Lessons Learned from Successful DR Programs

South Korea provides a utilization payment equal to the wholesale energy price. The incentive level was selected based on consistency, as DR resources are participating in the energy market like other supply resources. In the context of South Korea, this has shown to be effective in attracting participants through the aggregator-led process.

DR resources can participate in both economic-energy and reliability-capacity programs. In theory, this enables higher levels of activation, as DR resources are dispatched for economic and for reliability reasons. DR resources are provided an availability payment through the capacity/reliability program in exchange for being available to be dispatched during a reliability event. DR resources are also paid a utilization payment when dispatched by clearing the energy market or when dispatched administratively through reliability DR.

The payment for performance is determined based on the resources' actual curtailment and the highest variable generation cost at that time. Other jurisdictions and organisations that have both reliability and economic DR programs also have significantly higher participation in the reliability program.

Aggregators can provide strong performance, react in various circumstances and compete successfully against generation by following clear market rules. Automated response solutions are entering the market to further increase resource potential and diversity.

7.3 State of California

California is a state in the Pacific Region of the United States. With 39.5 million residents across a total area of about 163,696 square miles (423,970 km^2), California is the most populous U.S. state and the third largest by area. California's economy, with a gross state product of USD 3.0 trillion, is the largest sub-national economy in the world.[37]

[36] Ko, W. et al. "Implementation of a Demand-side Management Solution for South Korea's Demand Response Program". *Applied Sciences*, 2020, 10, 1751; doi: 10.3390/app10051751
[37] US News & World Report, accessed in March 2020 (https://www.usnews.com/news/best-states/california).

7.3.1 Background

California leads the US utility industry in conservation and efficiency measures and has been implementing DR programs for over 10 years.[38] The state implemented a number of test programs between 2003 and 2005 to support the electric system reliability as well as load management as a response to the energy crisis in 2002 – 2003 in the western US. By 2006, California's industries were already participating extensively in DR programs, accounting for 1,857 MW for reliability and 1,044 MW for "day ahead" notification programs. This same year, the California Public Utilities Commission (CPUC) approved a proposal by the state's three largest investor-owned utilities (IOUs) for the implementation of statewide DR programs focusing on Critical Peak Pricing, (CPP), Demand Bidding (DBP), and other targeted system reliability programs for 2007 to 2009.[39]

7.3.2 Programs and Experience

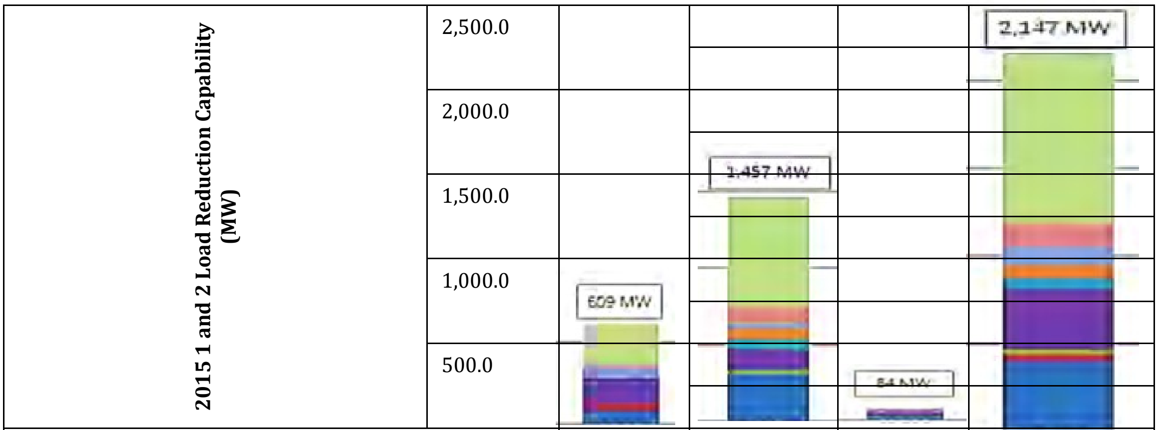
Since about 2010, the utilities in CA have been offering primarily in what are known as "manual" DR programs. To participate, commercial or industrial customers must have 12 months of billing and usage history before enrolling and can choose from several program options, including:

- Peak Day Pricing – Participants receive a discount on regular summer rates, but a higher price up to 15 Peak Pricing Event Days per year. Customers can try this program risk-free for 12 months: if the customer's bill ends up being higher than usual, the utility will pay back the difference.
- Capacity Bidding Program (CBP) – Participants commit to this aggregator-managed program on a month-by-month basis. On the months they opt in, they will receive either day-ahead or day-of notifications for load reduction events, which should not exceed a total of 30 hours per month. Customers must enroll with a utility-approved third-party aggregator to participate.
- Base Interruptible Program (BIP) – During a maximum of 10 events per month, participants lower their energy consumption to below its Firm Service Level (FSL). The FSL must be no more than 85% of the customer's highest monthly maximum demand and may be adjusted annually. Customers receive at least 30 minutes' notice of events, which last a maximum of 4 hours. Once enrolled, customers won't have the opportunity to discontinue until the following November.
- Scheduled Load Reduction Program (SLRP) – Open to customers that have an average minimum monthly demand of 100 kW or higher, this program lets participants select the times they'll reduce their energy consumption. Specifically, participants select one to three four-hour periods on specific weekdays during which they'll decrease their load to below a certain baseline. Participants have the opportunity to discontinue only once each year in November.
- Aggregator-managed Portfolio (AMP): In this program, the responsibility of program design falls to the aggregator. Because of this, the participation requirements and incentives vary depending on the aggregator.

[38] In 2010, California's peak electric load was approximately 60 GW. The California Energy Commission (CEC) had a goal to achieve 7 to 10 GW of total peak demand reduction and 1 GW of storage capacity by 2020.
[39] Proposal by PG&E in the 8/30/06 letter to CPUC and CPUC decision dated 10/30/06, permitting program expenditure of USD 2 million and peak demand reduction of 15 MW.

These programs have been successful in helping CA manage its electric loads and maintaining grid stability. A study by Lawrence Berkeley National Laboratory showed that the CA IOU programs provided about 2.1 GW of DR in 2015.[40]

Table 7-4: Load reduction capacity in California



	PG&E	SCE	5D G&E	Total
Non-Res-Real-time pricing		2.5		2.5
Non-Res-Interruptible rates	252.1	707.8	1.0	961.0
Non-Res-Demand bidding	21.0	114.5	2.6	138.1
Non-Res-Critical peak pricing	51.5	29.8	20.9	102.2
Non-Res-Air conditioner load control	2.7	64.3	3.1	70.1
Non-Res-Agricultural pump control		59.4		59.4
Non-Res-Aggregator programs	165.7	147.2	34.7	347.6
Residential – Peak time rebates		27.0	5.3	32.3
Residential – Critical peak pricing	36.9			36.9
Residential – Air conditioner load control	78.9	304.5	17.0	400.5

Source: Lawrence Berkeley National Laboratory, 2017.

However, recent studies have shown that California still has significant DR potential, and that the program has not reached all customer segments. The study also showed that the IOU programs rely on only a handful of participants to deliver the majority of the load reductions.[41] Other industrial sectors with significant DR potential that have not participated include:

- Wastewater Treatment Facilities;
- Agricultural Irrigation Pumping;
- Refrigerated Warehouses;
- Data Centres;
- Cement Industry;
- Dairy Processing Industry.

[40] "2025 California Demand Response Potential Study: Charting California's Demand Response Future". Final Report. LBNL, 2017.

[41] For example, the industrial, agricultural, and water (IAW) sectors accounted for about 30% of California's peak electric load in 2010 and has the potential to be a key contributor to DR and energy efficiency (EE) goals. Yet, in 2012 and 2013, two industrial participants contributed 50% of the load reduction for Pacific Gas & Electric's demand bidding program (DBP) and another two industrial participants contributed 25% of Southern California Edison's program.

In addition, California's electricity system is projected to undergo significant changes, as its climate-change-mitigation goals call for meeting 50% of the state's retail electricity sales with renewable energy by 2030, reducing greenhouse gas emissions to 40% below 1990 levels by 2030, 80% below 1990 levels by 2050. A 50% renewable electricity system means that the state will have significant penetrations of variable solar and wind-based generation, which may reach as high as 35 to 40% of the total delivered electricity by 2030. Variable generation is different from conventional generation as electricity is generated only when the wind and solar resources are available, and the outputs can fluctuate in a manner that is not entirely predictable.

Due to the need to reach more DR potential, as well as the projected future load uncertainty and variability that can result from the integration of large shares of renewables into the system, California has started shifting its DR emphasis from the existing "manual" mode of program implementation to faster and more responsive demand-response automation systems, or "AutoDR" mode of program implementation in its program planning beyond 2020, emphasizing the availability of instantaneous communications and the Internet of Things (IOT) while retaining the overall offerings.

7.3.3 Some Lessons Learned from Successful DR Programs

It has been shown in the case of California and other states in the US that:

- Targeting the right end uses and identifying the types of facilities best suited to benefit from DR can help achieve better results.
- Utilities or program sponsors must assist customers in understanding their facility's loads and provide financial and technical assistance to help customers achieve their peak load reduction potential cost effectively.
- Those programs that recognize the diversity of customers and provide them with a limited portfolio of options are the most successful at engaging and retaining participants.
- Although utilities traditionally targeted the largest commercial and industrial customers for DR, a number of successful programs have engaged small (<100 kW) and medium (<500 kW) customers.
- Automated technologies can greatly enhance a facility's ability to shed load for DR, provide consistency in load-shedding capacity, and provide customers with additional benefits such as detailed energy consumption data.
- Technologies with two-way communication capability further enhance the savings potential and reliability.

Utilities tend to operate energy-efficiency and demand-response programs independently but simultaneously. However, implementing a coordinated efficiency and DR program portfolio can help flatten the utility's system load curve, lower prices for power and gas, and defer construction of new plants.

7.4 Japan

Japan is an island country located in East Asia encompassing an archipelago consisting of about 6,852 islands, with the five main islands (Hokkaido, Honshu, Kyushu, Shikoku, and Okinawa) comprising 97% of the country's land area. With over 120 million people in a total area of 377, 975 km^2, Japan is among the most densely populated and urbanized countries in the world. A member of the G7 and G20, its nominal GDP is estimated at USD 5.4 trillion and over USD 43,000 per capita.

7.4.1 Background

Japan has no export or import electricity connections and the electricity market is geographically divided into 10 areas. Each area has a long-standing vertically integrated utility operating in it, previously collectively known as the general electricity utility. Connections between the 10 areas were historically limited, including the eastern part of the country operating at 50 Hz and the western part at 60 Hz. Of all the demand, 34% is commercial, and, at 37%, the industrial sector is the largest consumer of electricity, despite the sector's slight downward trend since the 1990s.[42]

Since 1995, Japan has gradually liberalized its electricity sector, beginning with power generation starting with the extra-high voltage sector and then expanding to the high voltage sector. The Japan Electric Power Exchange (JEPX) has been operating a wholesale power exchange since 2005, which mediates spot transactions and forward transactions of electricity. In 2012, the government began undertaking three phases of improvement, known as the "electricity system reform". The Organization for Cross-regional Coordination of Transmission Operators (OCCTO) was established in April 2015 as the first stage in the three-phase reform, fulfilling the role similar to an independent system operator. The electricity retail market was fully liberalized in April 2016, implementing the second phase of the electricity system reform.

In the 2018 revision of the Basic Energy Plan (the most fundamental government energy policy), implementation of stringent energy-saving measures was specifically highlighted for the first time. In 2020, the third phase of the electricity system reform will come into effect and the 10 general electricity utilities will then be required by law to separate their power generation and retail functions from their transmission and distribution functions.[43] The DR programs in Japan are operating in the context of this changing regulatory regime and certain upcoming programs, such as virtual power plants (VPPs), may benefit from this changing regulatory regime and the changing economics that accompanies it.

[42] "The Electric Power Industry in Japan 2019", Japan Electric Power Information Centre, p. 30.
[43] Kobayashi, T. & Okatani, S. "Electricity Regulation in Japan: Overview". https://ca.practicallaw.thomsonreuters.com/5-630-3729?transitionType=Default&contextData=(sc.Default)&firstPage=true&bhcp=1

In addition, part of the DR context in Japan is the memory of the impacts of the severe accident suffered at the Fukushima Dai-ichi Nuclear Power station in 2011. Due to a variety of reasons, including low levels of interconnection, the nuclear accident resulted in rolling blackouts. To reduce further blackouts and particularly to reduce the peak demand, from 2011 to 2015, the Japanese government implemented a range of behaviour-change strategies to communicate the need to change behaviours and reduce electricity use. This was accompanied by a mandated 15% reduction in peak electricity use by industrial customers. The mandated and voluntary appeals both had tremendous impacts, reducing summertime peaks in each of the following two years (see Figure 7-2[44]) and for the years to come. This experience highlighted both the potential for DR and the benefit of system resiliency but may not have implemented DR measures in the most economical way possible. The year of 2016 was the first year in which electricity consumers were not asked to reduce electricity consumption, and in 2017 the "Negawatt" market opened.

Figure 7-2: Japan's DR Response Post 3.11

Annual peak demand in TEPCO service area

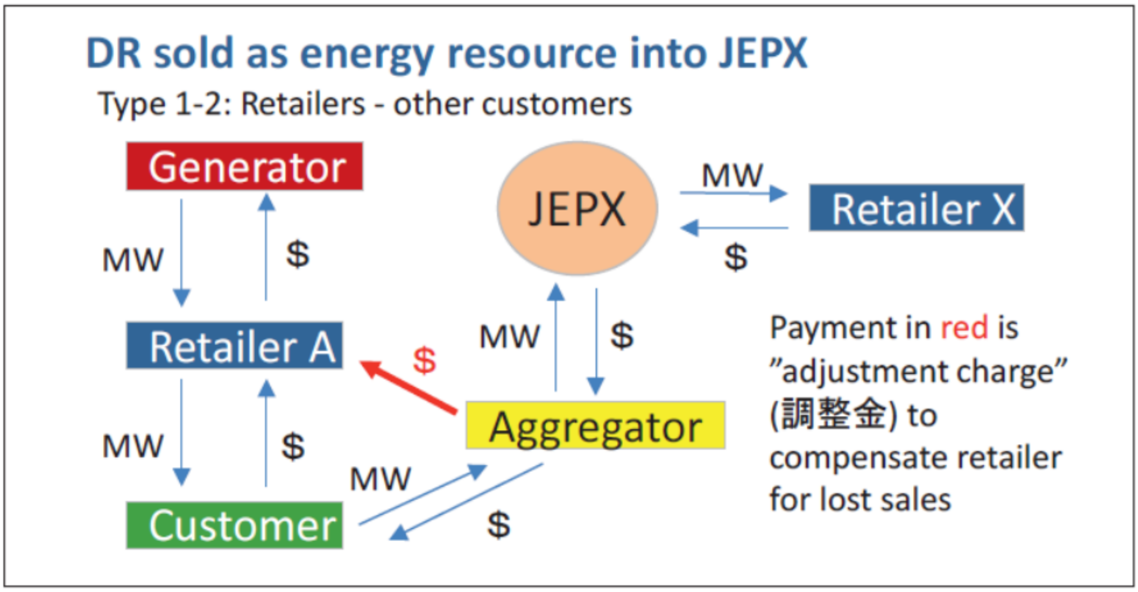
Date	2010 (July 23)	2011 (Aug. 18)	2012 (Aug. 30)
Peak load (gigawatts)	59.99	49.22	50.78
Reduction	(100%)	-18%	-15.4%
High temperature (C)	35.7	36.1	35.6

7.4.2 Programs and Experience

Encouraged by the demonstration that the C&I segment is capable of realizing significant peak-shaving following the Great Eastern Japan Earthquake (GEJE), Japan implemented several pilot programs before implementing the Negawatt trading market in 2017. The market operates based on a vision of DSM for large C&I end-users in Japan enabled by aggregators, who act as intermediaries in getting C&I customers to reduce energy consumption in response to requests from power companies. Aggregators bundle and are paid for this unused power and compensate participating end-users according to the amount by which they reduce their demand.

[44] Takahashi, Hiroshi. "Examining the Post-3.11 Demand Response: How Japan Overcame the Power Crisis". *Japan Spotlight*, 2013.

Figure 7-3: Diagram of Japan's Market for Negawatt Trading



Source: METI/ANRE in Yoshida, P. "Japan's Energy Conundrum". Sasakawa USA, 2018, p. 133.

A yearly auction is held, where bids for DR capacity are placed. Utilities then pay an annual sum, typically in the range of EUR 25 – 42 per kW, to aggregators, who will act as intermediaries and get the end consumers to reduce their load when called upon. Each aggregator uses a portion of this payment to compensate both the end consumer and the utility, since its revenue is decreased by the lowered power consumption. Since peak load is reduced, the generator can avoid investments into expansion of generation, transmission or distribution capacities. The market plays a role in ensuring grid stability. Price volatility on the JPEX is relatively low and the grid tariffs mostly rely on volume. The first auction for DR was reported to have gained about 1 GW of capacity from industrial and commercial power consumers. Utilities were mandated to bid and buy 20 MW each to start.

Under the vision that the Ministry of Economy, Trade and Industry (METI) has presented as part of the Sustainable Open Innovation Initiative, DR and other smart technologies could be aggregated into VPPs in the future. In this scenario, consumers could be tapped as a resource not only for reducing demand when power supply is short, but also for collectively storing and supplying power on a community-wide basis, to form a "virtual power plant" (VPP), a collection of distributed energy resources, including both supply-side and demand-side resources.

7.4.3 Some Lessons Learned from Successful DR Programs

Key lessons from this market's operation to date include:

- It is important to ensure that the utilities' interests are aligned with those of the policy-makers.
  - Policy-makers seek to promote DSM both for its individual-level benefits (e.g., reduced energy bills for consumers) and its system-wide benefits (e.g., increased flexibility from shifting energy consumption from peak to non-peak hours).

    - Japanese utilities' incentives remain essentially unchanged from before the GEJE. Energy providers still are invested in selling more kWh than fewer.
    - Unbundling is to be mandated starting in April 2020, and this is expected to somewhat help address utilities' incentives.
    - New markets, including "non-fossil value" markets, ancillary services, and capacity markets, may provide opportunities for DR resources to compete against generation.
- Starting new markets is no guarantee that they will be open, liquid, and competitive. The amount of electricity sold on Japan's wholesale power market, the JEPX), is still less than 3% of the total electricity generated, 15 years after its inception.[45]

7.5 Singapore

The Republic of Singapore is a sovereign city-state and island country located in maritime Southeast Asia. Its total population is approximately 5.6 million with a total area of 725 km^2. Its nominal GDP per capita is approximately USD 65,000 and it is one of the most expensive cities on earth. Singapore is a close neighbour to Vietnam with many similarities in climate and regulations.

7.5.1 Background

Singapore is considered as one of the leading countries in Asia in terms of DR application and also the leader in creating sandbox trials for advanced services. On October 22, 2012, the Energy Market Authority (EMA) issued a public consultation paper to collect suggestions about the best approach for implementing a DR program in the National Electricity Market of Singapore (NEMS). The consultation closed on November 19, 2012 and the program has been further refined based on the feedback received from all stakeholders (electricity licensees, potential licensed load providers, consumers, etc.).

Since 2016, the EMA has introduced several DR programs to enhance competition in the NEMS. Incentive payments to DR providers are derived from an uplift charge applied to all loads and charged to retailers. Consumers can participate directly or through retailers or DR aggregators, including DR services through the 2016 Project Optiwatt, which is for demand-side management (DSM) or through the 2016 DR program, which will be discussed below.

7.5.2 Programs and Experience

In April 2016, the NEMS introduced its first DR program for the wholesale market. This program allows DR resources to participate in both the wholesale energy market and the ancillary services market. It allows consumers to submit bids in the energy market to provide load curtailments and indicate their willingness to reduce their electricity demand at different price points.

The DR program is characterized by two distinct features:

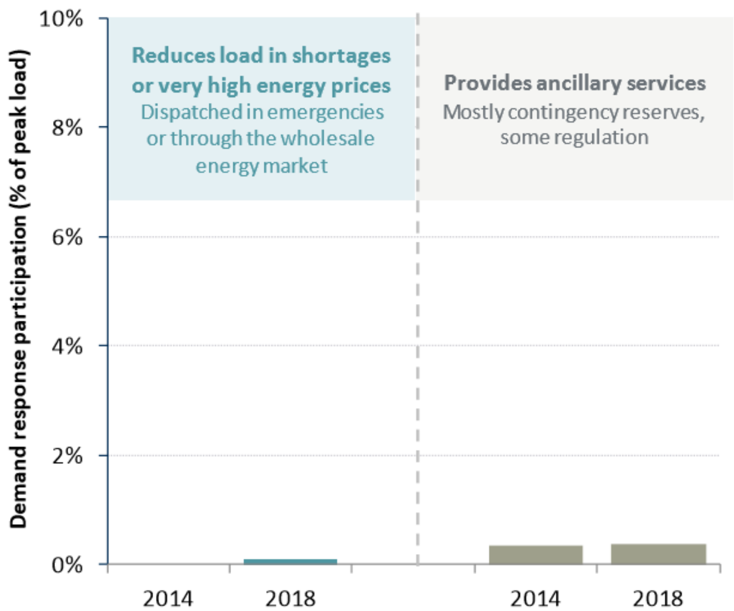
[45] Yoshida, P. G. ed. "Japan's Energy Conundrum". Sasakawa Peace Foundation, 2018, p. 136.

- **Demand-side bidding and the use of a self-nominated baseline**: This allows consumers to indicate their "willingness to consume" at various price points by adjusting their loads in response to real-time supply and demand conditions. It will be co-optimized with the existing interruptible load (IL) scheme where loads can be offered for the provision of reserves.
- **A consumer surplus sharing mechanism**: The compliant licensed load provider whose load reductions have been cleared can share one third of the additional consumer surplus generated as a result of the load curtailments dispatched.

The registered capacity of this program was limited to 7.2 MW in 2017.

Under the DR program, DR resources can also participate in the ancillary services market through the IL scheme. The IL service includes curtailable load as a substitute for spinning reserves. The figure below shows that DR participation impacts more on the peak load in the ancillary services market than in the wholesale market.

Figure 7-4: DR Participation in Singapore (2014 in comparison with 2018)



The eligibility criteria are still the same for both programs: a consumer with load facilities that are directly connected to the power grid at the same connection point may participate directly in the DR program if the load facilities have an aggregate curtailable load of at least 0.1 MW. To participate directly, a consumer has to register (a) to become a market participant and (b) the load facilities as a single Load Registered Facility ("LRF"). Consumers with load facilities that have a curtailable load of less than 0.1 MW may participate indirectly through a licensed retailer or DR Aggregator ("licensed load provider"). Such licensed load providers can aggregate the load facilities of multiple consumers within the same IL zone to be registered as a single LRF. The LRF must be able to offer at least 0.1 MW of curtailable load.

Big companies, such as Diamond Energy Company or CPvT Energy, have already participated in the load interruption programs to deal with abnormal events, such as unexpected peak demand or forced outages of power generation.

7.5.3 Some Lessons Learned from Successful DR Programs

Early in its DR implementation, Singapore had very limited demand response participation because of a combination of high penalty exposure and low energy prices (due to high reserve margins). Since 2016, Singapore's new DR program has been addressing this issue with two distinct features: the use of a self-nominated baseline and a consumer surplus sharing mechanism. This has improved the participation rate. In addition, a review of the program done for the Australian Energy Market Commission provided these following takeaways:[46]

- Demand response participation will be low if penalties are high and when energy prices are low.
- Energy participation on the supply side can be enabled through a baseline mechanism. The Singapore approach to the self-supplied baseline has different vulnerability to gaming than historical baselines, but its enforcement with penalties discourages participation.
- Participation in ancillary services can be encouraged by establishing qualification criteria and market mechanics for participation.

7.6 Australia

Australia is the largest country in Oceania, the world's sixth-largest country and world's largest island with a total land area of 7.692 million km^2. In 2017, Australia's GDP was USD 1,323 billion with a population of is 24.6 million.[47] What follows is an overview of the background, implementation history and lessons learned regarding Australia's DR programs which are relevant to Vietnam's DR program.

7.6.1 Background

Australia's markets are vertically structured and the national market is divided geographically into local markets. The National Electricity Market (NEM) represents 89% of the generating market and has been operating a wholesale power market since 1988. The wholesale market is highly concentrated and large vertically integrated generators or retailers make competition difficult. A large number of coal-fired generators in the market has kept prices relatively low and reduced incentives for energy efficiency. More recently, the NEM's transmission system has been evolving rapidly because of the increased penetration rate of variable renewable energy, including solar and wind.

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[46] "International Review of Demand Response Mechanisms in Wholesale Markets". Prepared for the Australian Energy Market Commission by the Brattle Group, 2019.
[47] Source: data.worldbank.org

Australia considers demand response as a flexible asset, which can help integrate more variable renewable energy, such as solar and wind, into the grid at the lowest costs. Australia recognizes that DR can play four roles in the power market: wholesale demand response, emergency demand response, ancillary services and network demand response. In 2017, the Australian Renewable Energy Authority (ARENA) and the Australian Energy Market Operator (AEMO) launched a trial of a DR program named "Reliability and Emergency Reserve Trader (RERT)". This trial is a three-year DR initiative lasting until 2020 and its implementation is still ongoing.

The RERT trial has been developed as proof demonstrating the project concept that the power transmission system can still be secure and reliable despite the integration of variable renewable energy into the energy market. As part of ARENA and AEMO agreement, an emergency DR program called "DR Short Notice RERT Trial" was developed. The DR Short Notice RERT Trial's objectives are to:

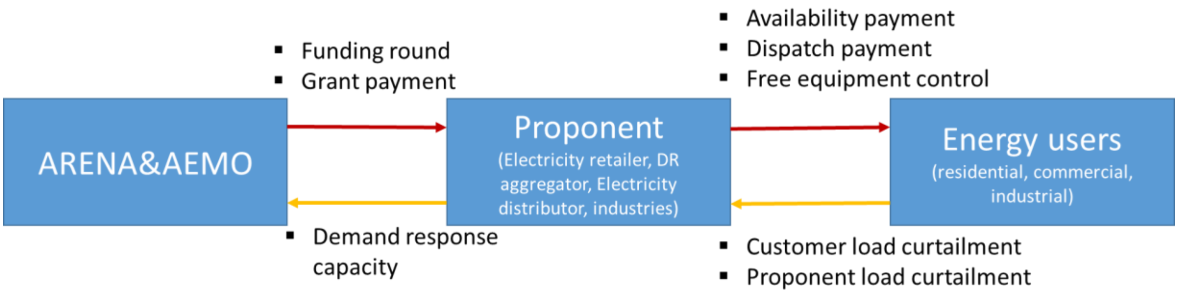
- Demonstrate that DR is an effective source of reserve capacity for maintaining reliability of the electricity grid during contingency events and that DR resources can be rapidly developed for deployment from summer 2017/18.
- Provide an evidence base to inform the merits and design of a new market or other mechanisms for DR to assist with grid reliability and security, allowing for greater uptake of renewable energy.
- Improve the commercial and technical readiness of DR providers and technologies to help demonstrate and commercialize the use of DR for grid security and reliability.

7.6.2 Programs and Experience

ARENA and AEMO launched a competitive three-year, AUD 37.5 million funding round to call for projects to drive innovation on grid management from various proponents. The competitive funding round was an open call not directed at a specific type of consumer and targeted a combined capacity of over 100 MW per year. Once the proposal of a proponent is accepted, the proponent becomes a short-notice (SN) RERT Panel member. The SN RERT Panel is a pool of providers, from which AEMO can contract for provision of DR services. Then, upon a short notice, the proponent has to manage electricity supply during peak demand periods. Two products were offered to proponents: Product 1, which is a 60-minute activation notification; Product 2, which is a 10-minute activation notification.

Figure 7-5 below shows the schematic of Australia's SN RERT Trial program. A proponent submits an application in response to the funding announcement and benefits from grants allocated by ARENA and AEMO. As part of its application, the proponent must include a knowledge-sharing plan leading to periodic releasing of project knowledge reports. In return, proponents must ensure that the stated capacity in their offer is available upon a SN. Before being accepted into the program, a proponent has to pass a testing period over which it can demonstrate its ability to reliably respond to a real RERT activation. The proponents accepted as SN RERT Panel members are diverse, including electricity retailers, DR aggregators, electricity distributors and industrial enterprises.

Figure 7-5: Schematic of Australia's SN RERT Trial DR program



Source: the Author.

Proponent's of the SN RERT Trail program used several models with energy users (see Figure 7-5). For commercial and industrial customers, models are based on load curtailment. This is done either manually by the customer in response to an SMS notification of the proponent or through automated remote control of users' loads by the proponent prior to an agreement between both parties. The DR equipment and measures deployed by proponents on energy users' sites include more than just energy consumption meters and monitoring devices and may also include individual energy reduction plans and intelligent remote controllers. Energy users who comply with the proponents' instructions are given compensation, including availability payment, energy payment or equipment control free of charge. The first-year implementation report of the SN RERT Trial showed that it was successful. For example, the proponents' total capacity contracted was 143 MW, but the result obtained was 163.6 MW, an overall increase of about 14.4%. Details about DR capacity results by end-user type is shown in the following table. Commercial and industrial customers performed better than the residential sector, which underperformed.

Table 7-5: DR Capacity (MW) Results by Customer Type

Customer Class	MW Contracted	MW Recruited	% Recruited/Contracted
Residential	18.3	14.3	78.1%
Commercial	34.1	43.8	128.4%
Industrial	90.5	105.4	116.4%
Total	143	163.6	114.4%

Source: Oakley Greenwood & ARENA, Demand Response RERT Trial, Year 1 Report, March 2019.

7.6.3 Some Lessons Learned from Successful DR Programs

The lessons learned from Australia DR experience are as follows.

- Awareness-raising and training for commercial and industrial energy end-users by proponents showing them the benefits of participating in a DR program was key to get them involved.
- The use of technology for data collection, remotely monitoring and controlling loads at end-users' premises was instrumental for success. By remotely controlling customers' loads, proponents were more prepared to respond to AEMO's demand for having all data at hands, thus reducing the non-reactiveness risks.

- Financial compensation offered to end-users incentivized participation in the program because for C&I customers, participating in a DR program might lead to operational and reputational risks or conflicting interests within the businesses.
- Proponents deliberately over-recruited participants and ensured sector diversity in order to compensate the default participants who might not be ready to cut down their load in due time.

Chapter

08

DR Financing Mechanisms in Shortlisted Jurisdictions

8 DR Financing Mechanisms in Shortlisted Jurisdictions

Utilities have relied on the adjustment of electrical load operations to provide grid services for decades to make operations and planning more efficient and less capital-intensive. Like demand-side management measures, today DR is part of many utilities' integrated resource portfolio. However, the role of demand response and how DR programs are financed have changed thanks to past experiences, technological improvements, and power market restructuring. This chapter provides an overview of the DR financing mechanisms in the shortlisted jurisdictions: how each of these jurisdictions obtained funding to operate their DR programs.

Typically, implementation budgets for DR programs comprise two separate components:

- The **program administration costs** are the operating costs needed to appropriately run the program. Program administration costs cover all program implementation-related costs such as management, marketing, and evaluation. But it does not cover payments to program participants for the results of their efforts.
- The **program incentives** are the payments disbursed to DR program participants for the results of their reduction efforts. They are separated from the program administration costs because the incentive payments can vary with the DR periods and the amounts of reduction required during those periods, while the administration costs are based on the design of the program and tend to be fixed.

A sustainable DR funding mechanism and the associated budget have to account for both kinds of costs just mentioned.

Funding mechanisms for DR programs vary from one jurisdiction to another. The most common practice is to have the utility ratepayers bear both cost components, namely the operating and incentive costs) through tariffs or special charges as allowed by regulations or other authorities, in a way similar to some DSM programs' funding. Other jurisdictions allow utilities to operate DR programs using their operating budget.[48]

With respect to benefits, the beneficiaries of DR programs include:

- The **ratepayers** through the reduction in peak electricity prices, or through incentives awarded proportionally according to their levels of effort in terms of load reduction.
- The **utilities** and the **regulators** by avoiding costly transmission infrastructure upgrades, relieving stress on the electric grid during the peak hours, helping the grid adapt to fluctuations in wind and solar energy generation, among others.
- Third parties providing specific DR functions such as aggregators, or improved efficiencies in jurisdictions with wholesale utility markets.

Fully accounting for the costs and benefits of DR programs requires close coordination among the **regulators, utilities** and **third-party providers** to make the needed changes to legislation, or through broader policies as well as grid modernization efforts.

[48] For example, California's utilities are compensated through regular filings for program funding for their operating budgets, and not from ratepayers.

It should be noted that in the past decade, only the United States and a few other jurisdictions (including those described in this chapter) have significantly relied upon and integrated DR as a resource. One of the reasons that these jurisdictions have been able to effectively utilize DR is because their electricity markets allow load (or load reduction) participation in the provision of energy and ancillary services. For these markets, DR has been implemented in wholesale electricity markets through regulations and market rules that allow demand response resources to participate alongside supply-side resources in energy, ancillary service, and capacity markets through market-based instruments.

Market-based instruments (MBIs) are mechanisms that put market actors in competition to provide different types of services. It is often through a **competitive bidding system**.

In the energy sector, **auctions** are one of two main types of MBIs commonly used to increase EE. The other main type is an EE obligation.

- There are two main auction mechanisms allowing market actors to submit bids: (1) through competitive tenders whereby the lowest-priced bid wins; (2) within a framework that sets the price for each unit of energy savings and invites key market actors to submit proposals for generating savings at a given unitary price.
- EE obligations (or EEOs for short; also known as energy-saving obligations, energy efficiency resource standards, energy efficiency performance standards or white certificates) require utilities to carry out a defined level of activity to deliver energy savings but allow the utilities the freedom to use the methods that they find most appropriate for doing so.

Given the cost-effectiveness of DR's traditional role for peak load management, as well as the maturing of a wider variety of demand response control and service types that can respond to the system needs including reliability, there can be new market opportunities for demand response. The Asia-Pacific region in particular is expected to see rapid growth as its electricity markets allow load participation in the provision of energy and ancillary services.[49]

8.1 Financing Models in the DSM Context

DSM programs across North America, Europe and Asia rely on a range of different mechanisms to meet the cost of program administration and delivery.

Ratepayer funding is the prevailing model of DSM cost recovery in North America. Under this model, DSM program costs are passed on to utility ratepayers, typically through a small "energy efficiency rider" on their bill based on their consumption. Other varieties of the ratepayer funding model enable DSM costs to be bundled with a utility's capital costs and included in the rates.

Energy efficiency obligations are the most common funding model in Europe. In this model, energy end-users are typically required to obtain a number of energy efficiency

[49] "Demand Response: Commercial & Industrial DR, Residential DR, and DR Management Systems: Global Market Analysis and Forecasts." Navigant, Inc. 2014.

certificates based on their energy consumption. Certificates are obtained through implementing energy efficiency or by purchasing them from others.

Government funding, carbon pricing and emissions trading, and non-regulated DSM models are used alongside the models mentioned above, or in a stand-alone fashion. The government funding model may involve a transfer of funds from one agency in the government to an energy program administrator or may take the form of a short-term stimulus provided directly by the funding agency to service and equipment providers or end-users. Carbon-pricing and emissions-trading schemes have been used in the US and Canada as a funding source for energy efficiency programs, typically by channelling funding through existing utility or non-utility DSM program administrators. Private, non-regulated DSM or energy services (provided by utilities regardless of whether they also administer publicly funded DSM programs) have become more common in North America in recent years as utilities seek new sources of revenue and face challenges from new entrants in the energy services market.

In some jurisdictions, utilities pay the cost for DSM administration and delivery without access to a cost-recovery mechanism. International donor organizations provide loans to developing countries for the purpose of designing and implementing DSM programs or portfolios. Revolving funds can provide end-users with capital to implement energy efficiency projects. These projects then sustain the funds through repayment partially or completely based on the energy cost savings.

The advantages and challenges of each of these DSM program funding models are summarized in the following table, along with examples of each.

Table 8-1: Summary of DSM program funding models

Funding Mechanism	Advantages	Challenges	Examples
International Donor Funding	International donor organizations provide loans to support DSM programs in developing countries.	Similar to the government funding model, but control is shared with one or more organizations external to the government. The funding application process may take two years or longer.	Mexico: Programa Nacional para la Sustitución de Equipos Electrodomésticos (PNSEE) India: Super-Efficient Equipment Program (SEEP)
Ratepayer Funding	Long-term mechanism capable of achieving ambitious goals. Costs shared among energy users based on their consumption. Considerable design flexibility.	Energy efficiency costs may be perceived as a tax, unpalatable among large energy users.	Over 40 US states; 9 Canadian provinces; South Korea; Brazil.
Carbon-pricing and Emissions-trading Schemes	Emission-reduction mechanisms can magnify their effectiveness by using generated funds to support DSM.	Market-based trading schemes involve significant design complexity. Politically challenging and may be perceived as a tax.	Canada: Federal carbon price. Quebec-California Cap-and-Trade System. US: Regional Greenhouse Gas Initiative (RGGI).
Revolving Fund	Initial investment can create a sustaining funding mechanism.	Not well suited to support small projects. Requires an initial funding source	Germany: KfW loans. Slovenia: Eko fund.

Energy Efficiency Obligations (EEO)	This market-based scheme does not require significant initial investment. Enables market creativity to find the most cost-effective solutions.	Initially complex to establish the market function. Costs may increase over time as "low-hanging fruit" is taken.	Britain; Austria; Denmark.
Utility Funding	Simple mechanism. Does not impact competition in regulated, monopolistic utility markets. DSM may be provided as a pure benefit for end-users, eliminating political challenges.	Places a significant cost burden on utilities unable to recover the amount through rates. May create a perverse incentive for utility program administrators.	Brazil: ANEEL legislation.
Private Funding (Non-Regulated DSM)	Simple mechanism. Market-driven. Revenue-generating opportunity for utility program administrators.	Energy efficiency may be disadvantaged by energy subsidies in a market without incentives or other program support.	The U. S.: Duke Energy Carolinas, Con Edison Services.

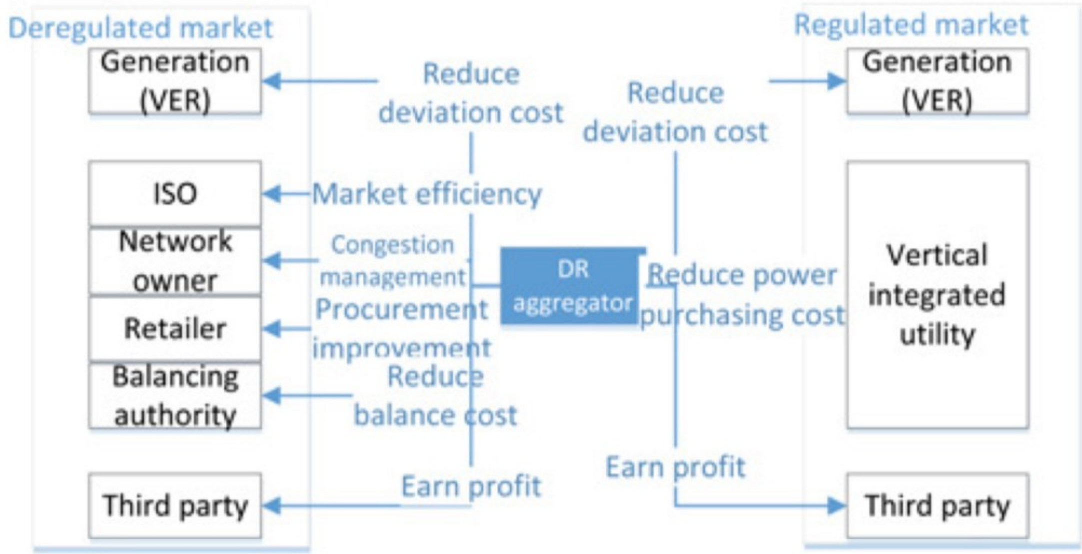
8.2 Financing for DR Programs in the Shortlisted Jurisdictions

Three of the jurisdictions studied operate in markets where DR providers can compete – all functioning using aggregators – in the wholesale power market.

Most consumers, including some small and medium enterprises, do not have the means (or the expertise) to trade directly into the energy markets because, for example, they are too small to manage the complexity. They require the services of an aggregator to help them participate. Aggregators pool many different loads of varying characteristics and provide backup for individual loads as part of the pooling activity, increasing the overall reliability and reducing risk for individual participants. They create one "pool" of aggregated controllable load, made up of many smaller consumer loads, and sell this as a single resource.

Where they are allowed to operate, DR aggregators act as entities that group customers and DR activities, and create business transactions by offering the added value to other entities in the market. A DR aggregator can be part of different entities or a third-party entity, depending the on the state of their market (deregulated and/or regulated markets as shown below.

Figure 8-1: Roles of a DR aggregator in the power market



Source: Fang, et al. 2017

In a deregulated power market, the vertical integrated utility was separated into several segments including the system operator (SO), the network owner, the retailer, the balancing authority etc. As illustrated, the retailer aggregators have potentially face few market barriers when participating in both the wholesale market and the retail market[50] In a regulated power market, the power generation is dispatched according to different rules such as policy needs, energy consumption, cost etc., requiring a more complex business model.[51]

Specific to aggregators, their business models, and financing mechanisms, there can be up to four possible models in increasing levels of complexity, or stages, depending on the market needs and regulatory flexibility. These models are based on the assumption that an aggregator may be an independent stakeholder in the electricity market with the same rights and obligations as the other stakeholders.

These four models or stages represent a variety of possible setups which may function in parallel to provide the needed services for some markets where the needed services can cover more than just DR aggregation. For example, it may be advantageous for the aggregator to offer a complete suite of services to the customer in addition to load management (e.g. heat, transport, energy management). This allows the aggregators to build a flexible portfolio as part of their business model, which can be used by other stakeholders in the electricity market, thereby also increasing their value. The figure below provides an illustration of these stages.

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[50] According to Fang et al, (*Business models for demand response aggregators under regulated power markets* ISSN 2515-8055, June 2107) the classic business models of DR aggregators under deregulated markets can is that the retailer opens up the DR program for the users, and arbitrage between the wholesale market and the retail market.

[51] For example: *A Business Model for Load Control Aggregation to Firm Up Renewable Capacity,* S. Oren, UC Berkeley, 2016.

Figure 8-2: Aggregator model set up stages

With respect to DR program financing, in South Korea and Japan, costs for the DR programs are embedded in wholesale rates and are not specifically visible to ratepayers. In Australia, the pilot program was separately funded with goals that include knowledge generation and sharing by all participants.

California's utilities are compensated for their DR programs through regular filings for program funding from their operating budgets. Funding of the Singapore DR program is based on the monetization of the consumer surplus provided by DR activities, and a portion of the surplus is used to incentivize demand-side participation.

Table 8-2 Summary of characteristics and financing source of jurisdictions covered

Jurisdiction	Negawatt Market	DR services: Economic/ Reliability/ Both	Charges: Capacity/Utilization/ Both	Cost Recovery through Regulatory Charges	Self-financing
California				X	
South Korea	X	Both	Both		
Japan	X	Both	Both		
Australia		Both	Both		
Singapore					X

- It is understood that every jurisdiction has its own unique characteristics for power supply and demand profile, which shape both the need and potential for demand response, as well as the program design and incentive levels. Therefore, an analysis is needed with all the relevant

Vietnam-specific factors in order to determine the necessary program details.[52] With regards to factors that ERAV may want to take into consideration in the design of the incentives, they include:

- Power supply portfolio, costs and availability.
- Peak periods.
- Electric rates/tariff structure.
- Deployment of technology, including for advanced metering infrastructure (AMI).
- The electrification and addition rates of additional end-uses, particularly electric vehicles (EVs).

- Beyond the particular characteristics of the power system, a comprehensive study other factors to consider in the design of incentives and DR program implementation can include:

- Consider a program approach based on achieving the cost-effective potential, rather than projecting only continuation of existing programs. This approach requires conducting DR potential studies on a regular basis.

- In the calculation of avoided costs, consideration should be given to the differences in avoided costs between peak and other hours, and allowing for customized avoided costs to be calculated for different kinds of DR interventions.

- Where possible, increase the adoption of technologies, and incorporate the use of standards (such as the Universal Smart Network Access Port or OpenADR).

- Allow for program flexibility to encourage greater participation, and consider program designs with aggregators.

[52] Regarding examples of country- or utility-specific incentive designs and program structure studies, please refer to:

1. *Demand Response Compensation Methodologies: Case Studies for Mexico* by D. Gagne et al, National Renewable Energy Laboratory, 2018.
2. *Best Practices in Utility Demand Response Programs, with Application to Hydro-Québec's 2017–2026 Supply Plan.* Prepared for Regroupement national des conseils régionaux de l'environnement du Québec (RNCREQ), 2017.

8.2.1 South Korea

The Negawatt DR trading system in South Korea provides signals to industrial consumers. In some ways, this South Korean system resembles the concept of a real-time peak load electricity tariff program in Vietnam, because it provides a way for the real-time prices on the wholesale market to be passed through to consumers via their agreements with DR aggregators. All DR participants work through aggregators and the services of the aggregators are paid through DR transactions. The services provided are separated from any supply contract. All DR aggregators are obliged to sell electricity to the Korea Electric Power Corporation (KEPCO), the monopoly utility, through the Korea Power Exchange (KPX). The KPX is primarily responsible for the day-to-day operation of the country's power grid and nearly 3,000 companies are participating in the electricity market.[53] The Ministry of Trade, Industry and Energy (MOTIE) has promulgated standards to maintain the reliability of the power grid and the KPX and the electricity utilities must follow these standards. The prices on the electricity market are determined based on the electricity demand prices predicted by KPX a day in advance and the supply bid prices of the electricity generation business operators. In principle, the electricity tariffs are established at the levels that would enable KEPCO to recover its costs as well as receive a fair investment return on capital used in those operations. Large consumers can purchase electricity directly from wholesalers. Smaller consumers directly purchase from KEPCO and pay regulated rates that offer a very weak incentive for commercial and industrial consumers to voluntarily participate in the demand response program.

Wholesale electricity prices have two main components: a system marginal price (typically the variable costs of generation under the merit order system) and capacity payment (typically fixed costs of generation). Variable costs and capacity payments are determined in advance by the Cost Evaluation Committee (mostly comprised of interested parties, government officers and industry experts). Reference capacity prices for generators apply differentially to each generation unit, depending on the start year of commercial operation, range from 9.15 won to 10.07 won (0.7¢ US – 0.8¢ US) per kWh and are subject to several conditions, including reserve capacity factors, hourly and seasonal adjustments, transmission losses and fuel-switching factors.[54] DR aggregators receive availability payments calculated in the same way as for generating companies in the competitive market. A monthly basic settlement payment is calculated based on the obligation reduction capacity using a standard formula. An actual performance-settlement payment (which varies according to the reduction duration time) is also made (see Figure 8-3[55]). DR aggregators bid into the day-ahead energy market and receive the system marginal price for energy when activated. The monthly basic settlement payment compensates for dispatch reduction deficiency with a basic penalty charge (see the fifth equation in Figure 8-3).

[53] Schwartz, D. L. *The Energy Regulation and Markets Review*, eighth edition. Law Business Research Ltd. 2019. p. 198. Retrieved at: https://thelawreviews.co.uk//digital_assets/5a97935e-c9d8-479f-9b78-1977ba275fa0/The-Energy-Regulation-and-Markets---Edition-8.pdf

[54] Bae, Kim & Lee LLC. "Electricity Regulation in South Korea". Nov. 2018. Retrieved at: https://www.lexology.com/library/detail.aspx?g=4a7f6594-b6b4-4249-a928-a0e02ed683e5

[55] Equation 2 on Page 8 of Ko, W. et al. "Implementation of a Demand-Side Management Solution for South Korea's Demand Response Program", Applied Sciences, 10, 1751; doi:10.3390/app10051751

Figure 8-3: Basic Settlement Equations Used in South Korea

$$\mathrm{DRBP}_{i.m} = \mathrm{ORC}_{i.m} \times \mathrm{BP}_m \times 1{,}000$$
$$\mathrm{IBPC}_{i.m} = \frac{\mathrm{TDRBP}_i}{\mathrm{ORC}_{i.m} \times \mathrm{MRT}} \times \sum_{t}^{m} DRD_{i.t} \times 2 \times DF_{i,t}$$
$$DRD_{i.t} = Max(RSO_{i,t} \times 0.97 - DR_{i,t},\ 0)$$
$$\mathrm{BPC}_{i.m} = Min(\mathrm{DRBP}_{i.m},\ \mathrm{IBPC}_{i.m})$$
$$\mathrm{FDRBP}_{i.m} = \mathrm{DRBP}_{i.m} - \mathrm{BPC}_{i.m}$$

$DRBP_{i.m}$ Demand response basic payment by monthly (KRW)
$ORC_{i.m}$ Obligation reduction capacity (MW)
BP_m Basic price by monthly (KRW/kW)
$IBPC_{i.m}$ Initial basic penalty charge (KRW)
$TDRBP_i$ Total basic settlement money during the contract period (KRW)
MRT Maximum reduction time (Max 60 h)
$DRD_{i.t}$ Dispatch reduction deficiency (kWh)
$RSO_{i,t}$ Reduction ordered by system operator (MWh)
$DR_{i,t}$ Dispatched reduction (kWh)
$DF_{i,t}$ Dispatch flag (1 for active, 0 for non-active)
$BPC_{i.m}$ Basic penalty charge by monthly (KRW)
$FDRBP_{i.m}$ Final demand response basic payment by monthly (KRW)

In the case of a reliability curtailment event, the KPX instructs a load curtailment an hour ahead. Customers participating in the load curtailment are compensated with payments for availability and performance. The payment for availability is calculated in the same way as the capacity price for generating companies and the payment for performance is determined based on the resources' actual curtailment and the highest variable generation cost at that time. Capacity payments to DR resources in the first 6 months of 2017 averaged 19,894.7 won/kW (approximately USD 16/kW) for reliability events.[56]

In the case of a price-responsive activation, the resources bid on the day-ahead electricity market and curtail the load if the demand reduction price is lower than the bid prices of generating companies and are compensated with incentives based on the system marginal price (SMP). In both cases, a pattern of regular power use must be evident in the calculation of the customer base load (with annually confirmed RRMSE less than 30%), which is calculated in a standardized way (Max 4/5 or Mid 6/10; see Section 9.2.1). For economic DR activation, the average SMP in the first 6 months of 2017 was 84.36 won/kWh (approximately USD 0.069/kWh). The DR program starts with seasonal procurement of DR resources. DR may bid into the day-ahead energy market within the committed load reduction, and then it is obliged to reduce up to the committed load reduction when KPX orders a load reduction in real time. The program is intended to encourage DR aggregators to participate in the market, and utilities, such as the KEPCO, are not allowed to participate.[57]

[56] Navigant. "Demand Response Discussion Paper Utilization Payments", prepared for the IESO, 2017.
[57] Navigant. "Demand Response Discussion Paper: Utilization Payments", prepared for IESO, 2017.

8.2.2 California

In the US, many states provide separate funding sources for energy efficiency and demand response. Under the traditional regulatory rate structures, the utilities' revenues are proportional to their sales of resources, including electricity and natural gas, while many utility costs are fixed, regardless of the sales. Thus, programs that improve energy efficiency among utility customers reduce sales and can have a negative effect on the utilities' profits. This created a significant barrier to effective utility-run energy-efficiency programs.

Utility rate "decoupling" is an adjustment mechanism that addresses this market barrier. Decoupling refers to policies designed to separate a utility's profits from its total electric or gas sales so that it does not have an incentive to try to sell more energy. Decoupling modifies traditional rate-making practices to adjust rates frequently to ensure that a utility's revenue is neither more nor less than what is needed to cover costs and a fair return. This is why most energy-efficiency programs in California are funded through a public benefits charge.[58]

California implemented decoupling through the Supply Adjustment Mechanism (SAM) for gas utilities beginning in 1978 and for the state's three investor-owned electric utilities by 1982. In 1996, the CPUC stopped the electric decoupling mechanisms due to restructuring of the electric power industry. In 2001, the California Legislature required that the CPUC resume decoupling for the three IOUs, which began in 2004 with the revenue requirement ruling. Currently, the revenue decoupling program has been combined with performance incentives for meeting or exceeding energy-efficiency targets. Initially, pilot DR programs were implemented as a part of the utilities' energy-efficiency programs. However, regulatory restrictions also prohibited energy-efficiency dollars from being used to support demand response.

[58] The California Public Utilities Commission's Decision 13-09-023 (September 2013) allocates incentive earnings among four major categories: Energy Efficiency Resource Savings; Ex Ante Review Process Performance; Codes and Standards Advocacy Programs; and Non-Resource Program:

- Incentives for energy-efficiency resource savings are capped at 9% of the resource program expenditure.
- Incentives for successful implementation of ex ante "lock down" are based on performance scores and are paid as an award of up to 3% of the resource program expenditure.
- Incentives are also provided for utility involvement in codes and standards programs in the form of a management fee equal to 12% of the approved program expenditure.
- For non-resource programs, utilities may earn a management fee equal to 3% of the non-resource program expenditure (exclusive of administrative costs).

Demand response programs in California must be funded from other charges to ratepayers, typically involving separate regulatory processes. For DR programs, California's utilities must obtain regulatory approval for their energy efficiency and demand response programs through separate regulatory proceedings; coordination of energy efficiency and demand response requires utilities and other parties to adopt consistent approaches in multiple regulatory processes. In October 2007, the CPUC directed California's three investor-owned utilities to "prepare a single, comprehensive statewide long-term energy efficiency plan" and to "integrate customer demand-side programs, such as energy efficiency, self-generation, advanced metering, and demand response, in a coherent and efficient manner". This action has allowed the three IOUs to offer statewide, comprehensive DR programs (see Section 2.3) since 2007, with regular filings for program funding from their operating budgets.[59]

Currently, California's utilities operate DR programs for all types of customers, including residential, commercial, agricultural or industrial.[60] Each of the utilities' program contains some form of incentive (derived from state-wide filing by the IOUs) for customers to reduce their electricity consumption during certain hours, called "events". For example, Pacific Gas and Electric, the state's largest investor-owned utility, offers the following DR programs for its customers:

- Peak Day Pricing – Participants receive a discount on regular summer rates, but a higher price up to 15 Peak Pricing Event Days per year.
- Capacity Bidding Program (CBP) – Participants commit to this aggregator-managed program on a month-by-month basis.
- Base Interruptible Program (BIP) – Participants must lower their energy consumption to below its Firm Service Level (FSL) during a maximum of 10 events per month. Participants receive at least 30 minutes' notice of events, which last a maximum of 4 hours.
- Scheduled Load Reduction Program (SLRP) – This program lets participants who have an average minimum monthly demand of 100 kW or higher select one to three four-hour periods on specific weekdays during which they will decrease their load to below a certain baseline.

Program participants must have 12 months of billing and usage history before enrolling. Typically, incentive payments to customers are based on a number of market factors, including:

- Hourly electricity rates (based on the time of day, season and temperature).
- Customer-selected thresholds (based on published rates).
- Capacity Payments (based on the committed load reduction amount and vary depending on the month, duration of events, and notification options).

Participants are notified of events through a variety of means (text, email and phone) and incentives can come in the form of a cash payment, bill credit, price signals, or other

[59] California Public Utilities Commission Decision on October 7, 2007.

[60] It is possible for California to offer a wide range of DR programs to address most of its customer segments due to the fact that the state has been focusing on more automation in order to access more DR potentials and speed up its DR response. California's push in automation by the utilities, including the installation of digital "smart" meters, have been funded by ratepayers but are off-set by increased energy efficiency and reduced billing administrative costs. PG&E "SmartMeter Program" funding was approved in 2006 at USD $1.74 billion.

means. DR programs are managed by utilities like PG&E, SCE and SDG&E, and paid for out of their DR program budget. Independent commercial entities, known as "aggregators" or "DR providers", also offer their own DR services and programs; these aggregators can obtain their incentives through the utility programs or directly from the capacities or wholesale markets.
It should be noted that the CPUC is aware that DR programs tend to operate on a different time scale than efficiency programs and the value created by DR depends on the time scale of the response, which is currently reliant on several notification and decision steps (hence the term "manual DR"). The state has commissioned research into a new framework for analyzing potential that will be more dynamic (for example, through more automated response, or "auto DR"), and reflective of the real-time value of the DR resources in order to develop better funding mechanisms for DR programs beyond 2020.

8.2.3 Japan

The Japan Electric Power Exchange (JEPX) has been operating a wholesale power exchange since 2005. This exchange mediates spot transactions and forward transactions of electricity. The Organization for Cross-regional Coordination of Transmission Operators (OCCTO) was established in April 2015 as the first stage in the three-phase reform, fulfilling the role similar to an independent system operator. Retail liberalization is currently ongoing, resulting in a large variation in rates available to consumers. Rates may or may not pass variability in the wholesale market onto consumers, depending on the retailer. Japan's main DR response for C&I customers is a Negawatt market, where aggregators collect participants and make bids on the wholesale market based on their potential DR actions. The aggregators must make payments to retailers and participants, and are not required to pass the price variability on to participants, but can make their own arrangements. As a result, Japan's programs appear to most closely resemble the CLP and EDRP programs proposed in Vietnam.

Japan's Negawatt trading market works as follows: utilities pay an annual rate per kilowatt of power saved to Negawatt aggregators, who use a portion of the revenue to pay rewards to factories and offices for the amount of usage they commit to curb on hot summer days and other peak-demand periods. The payments made to aggregators typically range from 3,000 yen to 5,000 yen per kW (Approximately EUR 25 to 42/kW).[61] The assumption is that utilities will be willing to pay for demand response because they would save considerable sums of money by forgoing capital investments to maintain surplus power-generating capacities. Right after the market opened, in the public invitations for offer for power supply in 2017 and 2018, the average price of DR offers was more than 30% lower than that of power supply offers (see Figure 8-4).[62] As a result, the contracted capacity won by DR offers was more than twice as large as that by power supply offers for two consecutive years.

[61] Jensterle, M. and Venjakob, M. "Smart power grids and integration of renewables in Japan" Wuppertal Institute, 2019.
[62] Yorita, Y. "Recent Developments in Virtual Power Plants and Demand Response". Institute of Energy Economics, Japan, July 2018. Available from https://eneken.ieej.or.jp/data/8003.pdf

Figure 8-4: Average contracted price of DR offers in public invitations for offers on power supply-demand adjustment capabilities in FY 2018 (Japan)

Average price (Yen/kW)	Previous FY	Present FY	Changes
Total	4,415	4,085	−330
Power supply	6,165	5,210	−954
DR	3,753	3,661	−92

*The average price was calculated as a weighted average by the Subcommittee secretariat by dividing the total of the contracted prices of power supply offers, etc. by the total of the contracted capacities.

Offered/contracted price	Previous FY		Present FY		Changes	
	Number of offers	Capacity (x 10MW)	Number of offers	Capacity (x 10MW)	Number of offers	Capacity (x 10MW)
Capacity acquired by public invitations for offers	−	132.7	−	132.2	−	−0.5
Offered capacity	63	165.4	55	175.4	−8	10.0
Power supply	6	54.2	7	59.3	1	5.1
DR	57	111.2	48	116.1	−9	4.9
Contracted capacity	41	132.0	46	132.2	5	0.2
Power supply	5	36.2	7	36.1	2	−0.1
DR	36	95.8	39	96.1	3	0.3

●Offers by parties other than the former general T&D operators (power generation/retail sector)

	Previous FY		Present FY		Changes	
Offered capacity	43	40.3	46	50.4	3	10.1
Contracted capacity	22	27.1	37	36.8	15	9.7

Payments to DR participants vary based on prices in the market and agreements made with aggregators. The aggregator must make a payment to both the DR resource and the retailer to compensate for the lost sales from the compensation received through the market transaction. The government aims to reduce peak demand by 6% through Negawatt trading by the fiscal year of 2030. Unbundling is expected to improve the economics of DR resources, and VPPs and the move towards "flexiwatts" may further contribute to DR competing directly against generation.

While currently DR resources compete in the market in the form of Negawatts, related programs have in the past been recipients of direct government support, specifically programs for smart communities, which cover more than just energy services and include broader community resilience issues such as care for elders.[63]

8.2.4 Singapore

Singapore began deregulating its wholesale electricity market in 1998 by creating the wholesale energy market known as the Singapore Electricity Pool. In 2001, the Singaporean Government created the Energy Market Authority (EMA) to oversee the retail electricity market. The National Electricity Market of Singapore (NEMS) began operating in 2003 with the EMA as its regulator. In addition to the real-time wholesale and retail electricity markets, the NEMS also procures and regulates ancillary services in the form of primary, secondary, and contingency reserves. The NEMS has a 30-minute dispatch period and settlement interval.

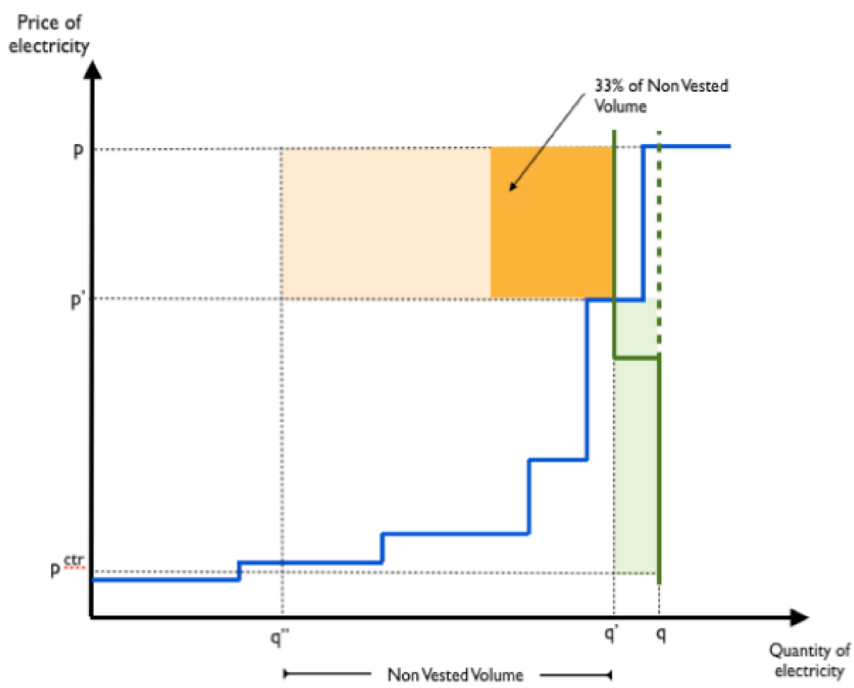
[63] Malme, R. "Japan Electric Market Update". Skipping Stone, May 2019. Available from https://www.peakload.org/assets/39thConf/Malme-Japan%20Update%20for%20PLMA%20v.3.pdf

The EMA prepared a public consultation paper on its program design in 2012 and finalized the program in 2013. Beginning in 2013, the DR programs operated by NEMS consisted of the interruptible load ancillary services program and the Energy Market Demand Response program (which started in 2015). EMA's Demand Response Mechanism (DRM) was designed to enable both retailers and independent DR aggregators (DRAs) to actively participate. The program involves DR resources bidding into the energy market and following dispatch signals from the system operator if their bids clear. A DR resource is required to bid a quantity that it will consume if it is not "dispatched" and an incentive payment and corresponding load reduction that it will provide if it is dispatched.[64]

Singapore's DR program provides an incentive payment to encourage participation by large loads and aggregators. Incentives also keep retailers "whole" because they will be settled on the basis of metered load. Incentive payments to DR resources are drawn from an "uplift" charge, which is applied to all loads and charged to retailers. The program also imposes penalties on cases of non-compliance.

Funding of the Singapore DR program is based on the fact that the program's actions can cause an increase in consumer surpluses. So, if and when consumers' DR action or actions have generated an observable benefit, this benefit would be monetized, and part of it should be used to incentivize demand-side participation. The figure below provides an illustration of the load change that would account for a proportion, currently set at 1/3, of consumer benefits from the reduction in prices (from p to p' – the area in the graphic subject to payout is shaded yellow).

Figure 8-5: Funding of the Singapore DR program

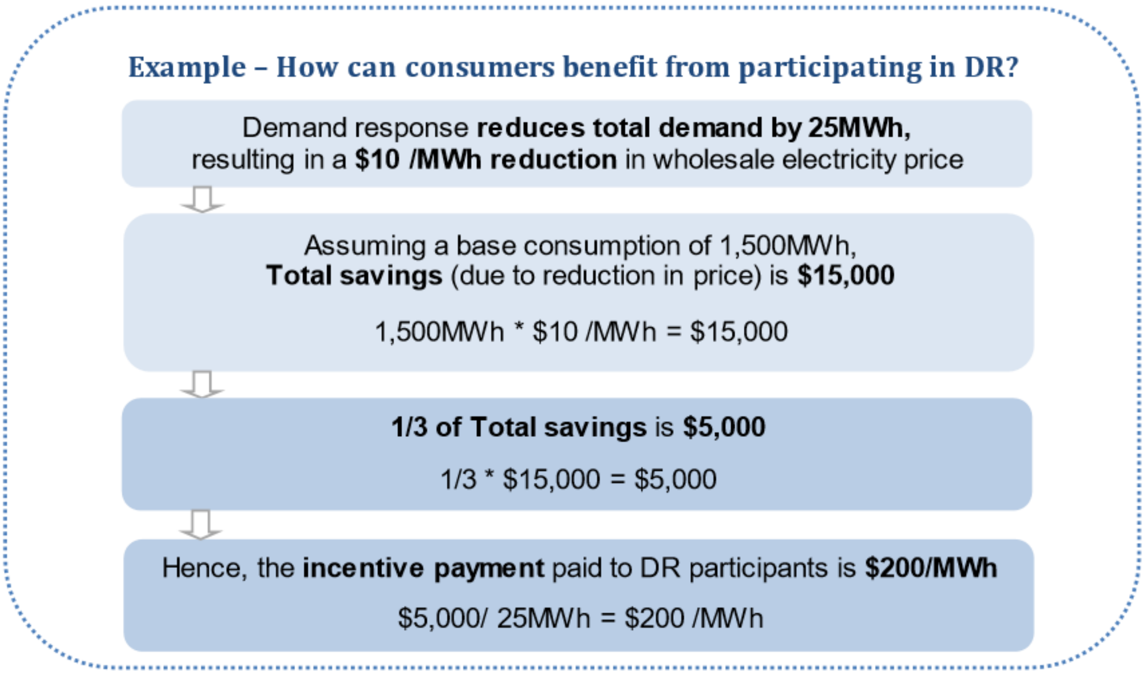


[64] Note that this approach allows EMA to avoid the need for an administratively determined customer "baseline."

Source: Cybele Capital Ltd., 2013

On the consumer side of the DR program, the consumers who participate can share one third of the savings obtained by the reduction in electricity prices as incentive payments, up to S$ 4,500/MWh (Singapore dollars) that is the cap of wholesale electrical prices.

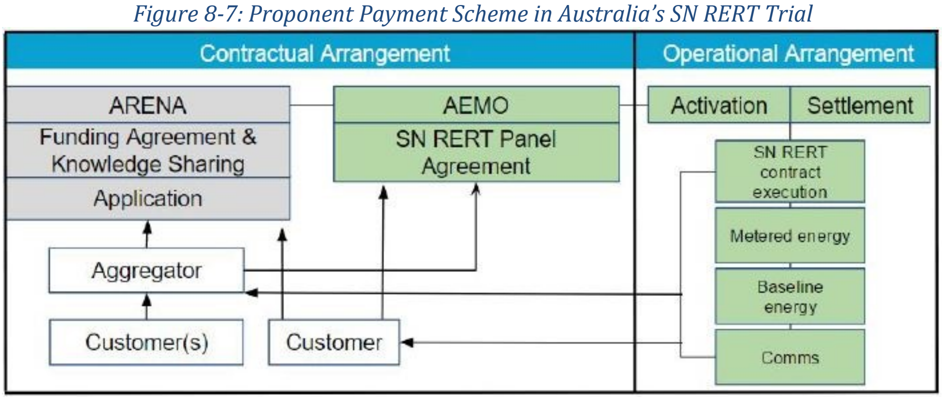
Figure 8-6: How consumers benefit from DR participation in Singapore



8.2.5 Australia

Australia's SN DR Trial Program is similar to Vietnam's Emergency Demand Response Program (EDRP) because participants in the program have to provide response within at least 10 minutes or 60 minutes after receiving a notification from AEMO. The notification availability period is the peak demand period during a business day from 10 AM to 10 PM. Proponents who have been accepted in the SN RERT Trial entered into contractual agreements with and are paid by both parties: ARENA and AEMO, as shown in the figure below.

Figure 8-7: Proponent Payment Scheme in Australia's SN RERT Trial



Source: ARENA, Demand Response Competitive Round Funding Announcement

ARENA pays for demand availability (AUD/MW/year) and AEMO pays for the usage charge (AUD/MWh) when a proponent has been successfully activated. There is no standard rate applicable to the usage charge, which ranges from AUD 0 to AUD 1,000 per MWh. A proponent proposes, as part of its candidacy, a rate for the usage charge and negotiates the exact value with AEMO. ARENA pays the proponent for DR technology deployment, performance, knowledge management and sharing while AEMO's payment is only related to the level of energy savings whenever the proponent is activated. ARENA's payment is split into the performance amount and the knowledge-sharing amount. ARENA's payment is released in instalments as follows: (1) a down payment of 5%; (2) 25% upon satisfaction of the Annual Anniversary Test for the first year; (3) 6 equal payments of the remaining based on satisfaction of the ongoing testing, performance and knowledge-sharing requirements. ARENA funds the SN RERT Trial through the Advancing Renewables Program (ARP). AEMO's funding is provided under the National Electricity Rules of the National Electricity Law of Australia.

ARENA's ARP funding is provided by the Commonwealth of Australia under the Australian Renewable Energy Agency Act 2011. An illustration of a yearly payment received by a proponent is shown in the following table.

Table 8-3: Illustration of a yearly payment received by a proponent under the SN RERT Trial

Annual Payments				
	ARENA Funding		**AEMO** Usage Charge	**Total Payment**
	ARENA Performance Amount (per year)	**ARENA** Knowledge Sharing Amount (per year)		
Scenario 1: 0 hours called	$1,000	$1,000	= $10 x 0 = $0	$2,000
Scenario 2: 10 hours called	$1,000	$1,000	=$10 x 10 =$100	$2,100
Scenario 3: 40 hours called	$1,000	$1,000	=$10 x 40 =$400	$2,400

Assumptions:

Performance Amount ($), paid by ARENA	*$1,000*
*Knowledge Sharing Amount ($), paid by ARENA**	*$1,000*
Usage Charge ($/MWh), paid by AEMO	*$10*
Reserve (MW)	*10*

Source: ARENA, Demand Response Competitive Round Funding Announcement

To gain an insight about how energy users are paid for during the Trial, we take a look at the model of ENEL X, which is one of the 10 proponents of the program. ENEL X contracted only commercial and industrial (C&I) customers to provide response to AEMO activation. The payment of ENEL X consisted of the availability payment and the energy payment. The availability payment, in AUD/MW/year, was linked to the user's daily availability to respond to a DR event. The energy payment, in AUD/MWh, was based on the energy saved during the DR event. "Availability payments is designed to cover the costs of searching for, contracting, commissioning, account managing, and ensuring continuous availability of each customer facility. Energy payments are intended to cover the customer's short run marginal costs including the costs of additional resources associated with load curtailment during DR events".[65]

[65] Source: ENEL X (ENERNOC). "ARENA Demand Response Trial: Knowledge Sharing Project Performance Report, December 21, 2018.

Chapter

09

Baseline and Measurement and Evaluation Methodologies in the Shortlisted Jurisdictions

9 Baseline and Measurement and Evaluation Methodologies in the Shortlisted Jurisdictions

9.1 Baseline and Measurement and Evaluation Theory

DR is typically used by utilities to provide capacity, energy or reliability to the grid. This is because DR programs enable utilities to avoid costly capital investments in generation capacity that would be used infrequently - primarily during peak hours to reduce demand. DR may also be used to provide capacity in constrained local areas of the grid to avoid costly upgrades. As such, the performance evaluation methodology used for determining the demand reductions and payments for a demand response program is the key to its success.

The measurement and evaluation (M&E) of a DR program means the determination of the demand reduction quantities and impacts. Typically, M&E for DR programs serves 2 broad purposes:

1. Settlement: the determination of the reduction in demand achieved by an individual program or market participants, and of the corresponding financial incentives, payments or penalties owed to or from each program or market participant.
2. Impact estimation: the determination of program-level demand reduction that has been achieved or is projected to be achieved used for ongoing program valuation and planning.

For effective DR program design, operation and evaluation, it is necessary to recognize the linkages between these two purposes. However, different methods may be used to determine each.

Baselines are required for measuring load reductions occurring during DR events. A baseline represents an estimate of the load that would have existed in the absence of the program and is needed for DR programs that provide incentives based on measured load reductions (settlement). Baselines are also required for the ex-post impact evaluations of DR programs. Not all DR programs require a baseline for settlement, because some depend on the measured load as the basis for settlement. Impact evaluation in general measures load reduction achievement, not load reduction capability. The discussion below does not address capacity markets, though results of an impact evaluation could be used to assess capacity performance.

Impact estimation in this context means determination of program effects. For DR programs, these effects can include load reductions (or load increases) related to a particular event or set of events, energy savings (positive or negative), monetary effects, and other impacts, including non-energy impacts and market impacts. The effects are typically determined at the program level, but they can be assessed at any level of granularity, depending on the evaluation scope. For the purpose of this paper, impact estimation is primarily focused on the calculation of load changes (both positive or negative) for a program as a whole or for specific customer segments (e.g., geographic regions, customer groups, industry, etc.). Impact estimation plays an important role in ongoing assessment of programs assessment and for program design or changes and can be a key element in the ongoing cycle of program development.

Generally, it is recommended that a methodology for evaluating the performance of demand-response program implementation should at least meet the following criteria:

- Accurate – The measurement method used should provide an accurate estimate of the load so that the DR program participants are credited only for load reductions associated with the event, thus minimizing any manipulation of the baseline.
- Flexible – The measurement method used should take into consideration some extraordinary circumstances during implementation, including excessively high loads and exceptions that may reduce the accuracy of the estimate.
- Simple – The measurement method should be described in straightforward language so that the requirements and calculations can be carried out by users.
- Repeatable – The performance evaluation calculations should be performed in the same way, whether the calculations are performed by the program participants, the third-party aggregator or the evaluator.

The general approaches outlined below illustrate the structure for designing performance evaluation methodologies that support these fundamental criteria. Recently, utilities have started to use DR programs to enhance grid flexibility by providing ancillary services, such as frequency response or load following. These ancillary services facilitate the integration of variable renewable resources by allowing utilities to maintain the balance between electricity supply and demand as the conditions change.

9.1.1 Performance Evaluation Methodologies of Demand Response Programs

This section briefly summarizes a number of main protocols for program evaluation in North America that can be applied to the measurement and evaluation of DR programs: the National Forum for the National Action Plan on Demand Response (NAPDR) released a detailed report on DR measurement and verification (entitled "Measurement and Verification for Demand Response"), which was developed with the goal of helping US states to advance the development and deployment of demand response resources. [66]

[66] "Measurement and Verification for Demand Response" was prepared for the National Forum on the National Action Plan on Demand Response: Measurement and Verification Working Group, issued by the U.S. Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) in February 2013.

In addition to the US National Action Plan on Demand Response document mentioned above, the International Performance Measurement and Verification Protocol (IPMVP) developed by the Efficiency Valuation Organization (EVO) is a standard reference document for measuring and reporting results of energy-efficiency projects. The California Public Utilities Commission and the Ontario Power Authority (OPA) have also developed protocols for the evaluation of demand response programs. These protocols are comprehensive and specifically designed to facilitate including DR as a resource. The methodologies recommended by NADPR and EVO are briefly described in their own sections below. California's is covered separately as part of the discussion below of the baseline and measurement and evaluation methodologies of the shortlisted jurisdictions.

The performance evaluation methodology for DR programs refers to the approach for estimating the demand reduction value of the product or service provided by a demand response resource. Generally, there are five main types of performance evaluation methodologies briefly defined as follows:

- Maximum Base Load: This methodology is based solely on a DR resource's ability to maintain its electricity usage at or below a specified level during a DR event.
- Meter Before/Meter After: This methodology is based on comparing the electricity demand over a prescribed period of time prior to deployment to similar readings during the ER response period.
- Baseline Type-I: This methodology is based on a DR resource's historical interval meter data. This may include other variables such as weather and calendar data.
- Baseline Type-II: This methodology is based on the use of statistical sampling to estimate the electricity usage of an aggregated DR resource where interval metering is not available.
- Metering Generator Output: This methodology is based on measuring the output of a generator located behind the DR resource's meter.

The above performance evaluation methodologies allow for characterizing the measurement approach used to estimate the reduction (or increase) in energy consumption by a demand response resource or participant. Baseline Type I and Type II performance evaluation methodologies are generally the two most commonly used methods to determine the energy response of a participant or resource during a DR event, or a scheduled event. DR programs can also use the Baseline Type I or Type II methodology to calculate the capacity provided. They are also referred to as the Customer Baseline Load (or CBL).

The Maximum Base Load, Meter Before/Meter After, and Metering Generator Output methodologies can also be combined with a Baseline Type I or Type II methodology to provide further details, or to improve the estimates of the reduction/increase in demand. For example, those situations that require historical data beyond the data used in a Baseline Type I or Type II can incorporate calculations using the Maximum Base Load methodology. The Metering Generator Output methodology can be used in combination with one of the two Baseline methods in a situation where there is a generator in use outside DR events as well as to respond to DR events. The Meter Before/Meter After methodology can be used for services that require information more closely reflecting the real-time conditions of the DR resource.

To sum up, these five performance-evaluation methodologies are applicable to most, if not all, DR situations. The design of the demand response program and the environment in which that program operates are the factors that can determine the performance evaluation methodology that is most suitable for the objectives and the DR target sector or sectors of the program.

For Baseline Type I and Type II, the calculation method can take a number of forms. Generally, the calculation method is specified by a combination of the following factors:

- Baseline window
- Exclusion rules
- Calculation type
- Baseline adjustments
- Adjustment window

The combination of the baseline window and the exclusion rule is used to identify the typical operating days and hours, or those that are similar to what the days or periods would have been without the DR event. Depending on the situation, the calculation types to be applied for performance evaluation include: average, matching, and regression.

- Average Calculation: The baseline for a given time interval is calculated as the average demand observed across a number of similar time intervals.
- Day Matching: The baseline is determined using short historical period for prediction.[1]
- Regression Analysis: Baseline is statistically determined using an extensive data set and establish the relationship between a number of different variables, such as weather, time of day and demand.

9.1.1.1 US National Action Plan on Demand Response (NADPR)

The NADPR document describes M&V methods that work best in various market and program contexts for DR, and identifies the types of inaccuracies that different methods may cause. [67] It also references the North American ISO-RTO (Independent System Operator – Regional Transmission Organization) Council's North American Wholesale Electricity Demand Response Comparison, which is a Microsoft Excel workbook that match the types of wholesale DR programs with corresponding performance-evaluation methodologies developed by the ISO-RTO. The workbook's content and calculation methodology are protected, but it is set up for use as an evaluation tool for DR programs.

[1] The historical period used vary by program: For example, New England ISO uses the data related to five similar days prior to the current date to calculate CBL, while California ISO (CAISO) uses the data related to three similar days prior to the current date for this purpose. In South Korea, the data related to four most energy intensive days among last five days is used.

[67] "Measurement and Verification for Demand Response," prepared for the National Forum on the National Action Plan on Demand Response (NAPDR): Measurement and Verification Working Group. U.S. Department of Energy 2013.

9.1.1.2 EVO

The Efficiency Valuation Organization (EVO) publishes the IPMVP in three volumes. The IPMVP presents one framework and four measurement and verification (M&V) options for transparently, reliably and consistently reporting a project's savings. The protocol is widely used for verification of energy and water savings from individual efficiency projects but does not directly address measurement of program-level savings, as it provides guidance rather than requirements. IPMVP Volume I is a guidance document describing common practices in measuring, computing and reporting savings achieved by energy or water efficiency projects at end-user facilities and is applicable to DR projects. M&V activities covered by Volume I include the following: site surveys, metering of energy or water flows, monitoring of independent variables, calculation, and reporting, which can be used to measure results for DR participants. By following the IPMVP's recommendations, these M&V activities can help produce verifiable savings reports.

The IPMVP is intended to be used by professionals as a basis for preparing savings reports. In this case, DR participants must establish their own specific M&V plans that address the unique characteristics of their projects. Because the IPMVP is not a standard, there is no formal compliance mechanism for this document. Adherence with the IPMVP requires preparing a project's specific M&V plan that is consistent with IPMVP terminology and the DR program measure or measures. It is also worth noting that the IPMVP is not designed for measuring demand reductions in real time, particularly those found in demand response programs.[68]

9.2 Baseline and Measurement and Evaluation Methodologies in Shortlisted Jurisdictions

9.2.1 South Korea

KPX's guidelines indicate that the customer baseline (CBL) calculation method used should be either MAX 4/5 or Mid 6/10. The Max 4/5 method involves making calculations by using the normal working-day electricity usage for 5 consecutive days. To calculate the CBL, the smallest electricity usage day of the 5 days is first excluded; then, the average usage for 4 days is used in calculating the Max 4/5 CBL. The Mid 6/10 method involves make calculations based on the electricity usage during a normal working day for 10 consecutive days. Two days are excluded from the top and bottom of the 10 days, respectively. The average usage of the remaining six days is used to calculate the Mid 6.[69]

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[68] The NADPR documents indicated that EVO indicated that a protocol for measuring real-time demand reduction is under development at that time. EVO has not yet released DR-specific protocols.
[69] Ko et al., "Implementation of a Demand-Side Management Solution for South Korea's Demand Response Program" Journal of Applied Sciences 2020, 10, 1751; doi:10.3390/app10051751 pp. 4.

To register as a DR resource in the Korea electricity market, the RRMSE (relative root mean squared error) value must be less than 30%; if it exceeds 30%, the customer is not allowed to join the DR market. The RRMSE is calculated by dividing the RMSE (root mean square error) with the average value of electricity data. If the RRMSE value becomes higher, conformity of power usage pattern decreases, which makes it difficult to judge the reduction value accurately. KPX performs an annual RRMSE assessment, and that result determines whether the DR customer can participate in the DR market for one year.

9.2.2 California

California's protocols are contained in the CPUC's *California Energy Efficiency Evaluation Protocols: Technical, Methodological, and Reporting Requirements for Evaluation Professionals*, which provide comprehensive protocols for EE and DSM programs, and are specifically designed to facilitate including DR as a resource. The CPUC protocols provide guidance on the following areas:[70]

Ex post Impact Methods

The protocols outline the standardized approaches for estimating aggregated impacts, including:

- Regression: Regression is the only method that is equally suitable for producing both ex-post and ex-ante results.
- Day-matching: Day-matching approaches offer a simple, intuitive approach to generating estimates of load reduction. The method does not provide a solid basis for ex-ante estimates.
- Sub-metering, duty cycle analysis, and operational experiment: These are alternative forms of data acquisition. Each of these will feed into one of the above methods, with regression being the most likely approach.

Results produced by the above approaches can then be applied to ex-post estimates of load reduction.

Ex-ante Estimates

The protocols cover a long list of issues for consideration, as listed below, in developing ex ante load reduction estimates, which are designed to support program and resource planning:

- DR Occurrence: Day types, time periods, event window and extreme conditions.
- Participant and geography: Who will participate and their geographic locations.
- Uncertainty: Confidence level of load reduction estimates.

[70] *California Energy Efficiency Evaluation Protocols: Technical, Methodological, and Reporting Requirements for Evaluation Professionals*. Public Utilities Commission, State of California, 2006.

Other issues identified by the CPUC protocols include those relevant to general program outcomes (e.g., free-ridership, persistence and long-term impacts). Most importantly, the CPUC protocols include the concepts of the 1-in-2 and 1-in-10 weather conditions, allowing for the projection of ex post results onto potential future weather scenarios based on the historical weather patterns by simulating typical (i.e., 1-in-2) and extreme (i.e., 1-in-10) weather conditions.

Reporting

In addition to the estimation protocols, the CPUC protocols also include discussions of consistent reporting protocols in order to facilitate making comparisons across programs, including the following aspects: the reporting format, the daily results reporting periods, the day types and events, and statistical reporting.

9.2.3 Japan

The Ministry of Economy, Trade and Industry (METI) drew up initial guidelines, including the baseline calculation standards, and opened a market in April 2017 for “negawatt trading”, in which aggregators pay consumers to curb their electricity use, and then sell the resulting spare capacity back to the grid. The guidelines outline the basic policies for the trading as a reference for energy resource aggregation business (ERAB) stakeholders (e.g., the method of assessing the amount of electricity).

METI stipulated the standard baseline calculation methods, which are the criteria for the baselines adopted in principle, which, in terms of DR for longer durations, were based on the data from historical electricity demand data, while those calculated for short periods of DR were estimated based on the amount of electricity demand recorded in the period immediately before the implementation of DR. Based on these approaches, the guidelines stipulate specific methods for calculating such baselines. Actually, the guidelines encourage buyers of suppressed demand to demand “accuracy”, “simplicity” and “fairness” in transactions and the baseline attempt to meet those needs.

The guidelines propose several methods of calculating the baseline, acknowledging that a standard baseline is not always appropriate and some flexibility is available. Methods for conducting a test to determine whether the standard or the alternative baseline is an appropriate estimate of demand are provided. These methods cover how to calculate the RRMSE and recommend the option of using an alternative baseline if the value is greater than 20%. Baselines also vary with the size of the DR resource and the final purchaser. Two kinds of cases are explicitly treated differently: (1) the case of DR with a relatively short reaction time and duration; the case of DR with a relatively long reaction time and duration. The baseline varies depending on whether the event occurs on a weekday or over the weekend. The standard baseline is based on the concept of statistical estimation load.

9.2.4 Singapore

Setting the baseline and measuring load reduction are issues central to demand-side bidding. These issues are particularly challenging for Singapore in its context of an energy-only market, with no capacity market or day-ahead market. Therefore, the Singapore Energy Market Authority (EMA) conducted extensive studies on baseline determination before establishing the methodology, including a pilot of the "10-in-10 day" baseline methodology. EMA settled on an approach where the determination of baselines should be self-declared by demand-side load providers (DSLPs). Because historical baselines were considered to be prone to gaming, such a self-determined baseline was designed to alleviate the concerns about artificially inflated baseline consumption.

EMA's rationale for choosing this approach (where the baseline is set based on what the licensed load providers bid into the market) was that the load reduction is verifiable and the risk of gaming is mitigated by the threat of being penalized for loads falling below 95% of the baseline bid.

This "self-declared baseline" approach for Singapore's DR program is fundamentally different from that of FERC and enables the licensed load providers to use their preferred methodology in estimating their baseline and adjust their bids based on commercial considerations when bidding into the market. The EMA allows a 5% tolerance threshold (i.e., if licensed load providers are compliant for at least 95% of the dispatch schedule, they will not be penalized). Because the baseline is a "self-declared" one, licensed load providers can factor the potential deviation into the load reduction when they bid into the wholesale electricity market. This is to ensure that the curtailment of loads offered under the program is an explicit action taken by the licensed load providers and that such an action would not have otherwise occurred under business-as-usual circumstances. This approach is expected to provide the licensed load provider with greater flexibility in managing their load by bidding in only the load that can be curtailed during specific periods.

9.2.5 Australia

The ARENA and AEMO DR SN RERT Trial used the California Independent System Operator (CAISO) "10 of 10" baseline methodology to define the baseline consumption of the proponents. To determine the baseline, AEMO used an aggregate customer consumption value of the proponent as a portfolio and not on an individual-customer basis. After a proponent is activated, AEMO only uses the aggregated electricity demand of all the national metering identifiers (NMIs) and data streams in the list provided to calculate the baseline and the energy savings – baselines and activated reserves of individual NMIs and data streams are not calculated .

However, some limitations were found about the "10 of 10" methodology used. The methodology was deemed accurate for large industrial and commercial consumers with a consistent day-to-day load profile. But the "10 of 10" methodology is deemed inaccurate for highly weather-sensitive loads, for example those loads influenced by rooftop PV generation, those loads that vary from day to day in a consistent pattern, and those highly intermittent loads.

To address this issue, a study was conducted on baseline methodologies for demand response activities.[71] The study modelled the relative accuracy, bias and precision of the "10 of 10" methodology and other suggested baselines by taking four steps: (1) developing simulated event days; (2) testing the suitability of the "10 of 10" approach by customer class and by jurisdiction; (3) testing the ability of alternative approaches to provide better baselines; (4) comparing the results and identifying the preferred baseline approach or additional analyses needed. The study results suggest that for loads which cannot be predicted by the "10 of 10" methodology, anchoring or control groups must be used. Anchoring means establishing a baseline by assessing a facility's shape of consumption on those days with similar temperatures in the past and the facility's consumption in the period before and in the period after the event day. A control group is a group of customers whose consumption on the event days can be assumed (or has been shown) to be similar to that of those customers who have been activated by AEMO. The value of the savings provided by the DR is then the difference between the control group's consumption on the day of the DR event and that of customers activated as DR resources.

9.3 Best Practices and Pitfalls

The measurement methods and results of DR programs are affected by (and can also affect) different aspects of a DR program, including planning, design, and operations. The M&E methodology as well as specification for incentives, program structure and rules, and the cost-effectiveness analysis all need to be considered as part of an integrated DR program design. As with the DSM program design, M&E method development for DR programs can be an iterative process: the initial design and implementation should be monitored, evaluated and modified based on the implementation experience.

In addition, producing accurate estimates of DR participant and program performance through measurement and evaluation is important for a number of reasons, including:

- Accurate payments to program participants can lead to improved market efficiency at both the wholesale and retail levels.
- Reliable measurements of DR performance can lead to an improved ability to predict DR response at the individual and aggregate levels.
- DR performance is a key input to planning and design of retail DR programs, especially in determining their cost-effectiveness.
- Consistent and reliable measurement of DR performance serves as the basis for fair and transparent financial transactions for market participants.

[71] Oakley Greenwood, ARENA, "Baselining the ARENA-AEMO Demand Response RERT Trial", September 2019.

Chapter 10

Summary

10 Summary

In Part I, we provided an overview of the DR-related actions taken by Vietnam in the past and identified the expected areas to be focused on in this assignment. Building on these outcomes, in Part II we have focused on looking for and examining relevant international examples that can inspire future program design in Vietnam. Following our analysis, we have found answers to the five questions, as summarized below.

1 What are the most relevant jurisdictions?

Starting with a long list of jurisdictions, we used a subjective multi-criterion selection method to develop a short list of five jurisdictions with potentially valuable examples for Vietnam. This assessment has resulted in a shortlist of five jurisdictions, namely South Korea, Japan, Singapore, California and Australia. These five jurisdictions' DR programs were reviewed to answer the following questions:

2 What characterizes the success of those initiatives?

3 What are the important lessons learned for Vietnam?

Chapter 7 of this paper describes the characteristics of each of the five shortlisted jurisdictions' DR initiatives and identifies some important lessons learned that could be relevant to the situation in Vietnam. The lessons learned from each jurisdiction are summarized below.

South Korea

South Korea has a partially liberalized electricity market that focuses on enabling a limited level of competition in the generation segment, whereas the retail, transmission and distribution business is controlled by the former monopoly utility, a situation somewhat similar to that in Vietnam. The Korean Power Exchange (KPX) enables a Negawatt market to operate, allowing demand response assets managed by aggregators to compete against generation. The market enables reliability-based responses and economic DR through hour-ahead and day-ahead notification times, respectively. The market has been operating since 2014 and has been growing steadily as aggregators and consumers gain more experience with its operation, highlighting the value of steady operation and regular market rules in attracting participants.

California

California leads the US in efficiency measures and has a long history of DR programs. Most of California's programs are "manual" DR programs, where customers must have 12 months of billing history to participate. Programs include the following: peak-day pricing; a capacity-bidding program; a base interruptible program; a scheduled load reduction program; and an aggregator-managed portfolio. All told, these programs provide over 2.1 GW of DR. California's experience with a variety of programs may offer some important lessons for Vietnam, such as the following: the importance of targeting facilities best suited to DR; the need for utilities or program sponsors to be engaged in improving customers' understanding of their load; a limited portfolio of options for diverse customers can be successful at engaging and retaining participants; the viability of small and medium C&I customers in DR; how automation can further enhance savings potential and reliability.

Japan

Japan is in the midst of comprehensively restructuring its electricity market. The wholesale power exchange has a long history of operation, and the retail market is in its final stage of liberalization, which involves separating retail from transmission and distribution in 2020. Japan had its first experience with DR when dealing with the aftermath of the Fukushima nuclear accident by taking mandatory and voluntary measures to reduce peak demand and using rolling blackouts for several years until the power system stabilized. The Negawatt market opened in 2017 with a focus on using aggregators as intermediaries who compensate both customers responding to the DR events and retailers for the lost sales. The market is relatively new and does not appear to have grown rapidly, though it has enabled many network-stability services. Aggregators have played an important and successful role in the market, and are introducing new technologies, demonstrating the kind of major opportunity that Vietnam can also seize. The importance of aligning the utilities' interests with those of policy-makers is another lesson that the Japanese experience can offer.

Singapore

Singapore's market is an "energy-only" market (as opposed to "capacity market") in the sense that it does not provide long-term availability payments to demand resources to secure sufficient capacity to meet future peak demand. In such a market, DR participants and generating companies earn revenues by selling energy and ancillary services. This distinction between the "energy-only market" and the "capacity market" is important because DR participants can receive higher payments by participating in a capacity market than by participating in only an energy market alone.

Singapore's DR program was implemented in 2016, but participation in the program has been limited. This was because the overall high reserve margins in Singapore limited the frequency of energy price spikes, thus reducing the attractiveness of demand response and the economic value of curtailing load. To encourage greater demand-side participation, the EMA has lowered the entry barrier by allowing aggregation of load facilities that meet the participation size threshold of 0.1 MW and introduced a penalty for non-performance to deter non-delivery of scheduled interruptible-load services. As for ancillary services, currently seven registered facilities provide interruptible-load services, with a total capacity of 27.5 MW.

Australia

Australia has long operated a whole power market and a vertically integrated market. The market is dominated by large generating companies and retailers and has quite a number of coal-burning generating companies. Also, a quickly increasing number of solar-based generating businesses is entering the generation market, creating challenges for both market operation and system stability. The country is currently completing a three-year DR pilot to demonstrate that DR is an effective source of reserve capacity and provide a body of evidence regarding the merits and design of a new market or mechanism to effectively support DR. The pilot is also expected to improve commercial and technical readiness of DR providers and technologies. Australia's experiences highlight the impacts that rapid changes to generation technology can have on grid stability and the role that DR can play in helping ensure reliable operations. The pilot project shows that well-structured interventions can result in significant learnings for participants, who by complying with the compulsory requirements knowledge and experience-sharing, can disseminate the learnings across the entire power generation and supply industry.

With respect to the remaining questions below,

4. What are the financing mechanisms used in these shortlisted jurisdictions?
5. What are the baseline and measurement and evaluation methodologies in use in these jurisdictions?

Chapters 8 and 9 of this section cover the financing mechanisms and M&V techniques employed by each of the shortlisted jurisdictions. Several of these methods can be helpful and useful for Vietnam in designing its own M&V system and developing the general principles that can guide the M&V process.

South Korea

South Korea offers payments that are equal to the wholesale energy prices to DR market participants. The type of payment was selected on the basis of the consistency to renumeration for other resources (generation), and has proven effective in this context for attracting market entrants. DR resources receive both availability payments and the system marginal price if activated to participate in the economic program, just like generating companies. For reliability events, they also receive both availability and activation payments based on the actual curtailment and the highest variable generation cost at the time. The total current demand response capacity is nearly 4.3 GW.

The KPX has developed a baseline calculation method based on the average of previous comparable periods of consumption and the minimum RRMSE values that DR resources must meet and maintain to remain in the market.

California

The utilities in California are required to employ appropriate methods to procure economic DR resources and are allowed to recover costs of their comprehensive DR programs through regulatory filings for program funding for their operating budgets. Comprehensive protocols for evaluating DR resources have been developed and must be applied at the state level. For the utilities operating DR programs, the protocols define and permit the application of ex-post impact assessment methods, ex-ante methods, as well as consistent reporting protocols.

Japan

Japanese aggregators are compensated through transactions made on the JEPX and use only that source of compensation to compensate their customers. The assumption is that the utilities are willing to pay for demand response because they can save considerable sums of money by forgoing capital investments to maintain surplus power-generating capacities. Until unbundling is completed, the utilities' incentives cannot be supported by this assumption. Standard baseline calculations are differentiated by long and short duration DR events, and reflect suppressed-demand buyers' need for "accuracy", "simplicity" and "fairness" in transactions. A standard test based on the RRMSE value is used to determine whether alternative baselines are applicable.

Singapore

Funding for Singapore's DR program is supplied by an additional electricity tariff known as the Hourly Energy Uplift Charge (HEUC). But in the long run, the program's funding will be supported by the prospect that the program's actions can cause an increase in consumer capacity surpluses. Thus, if and when consumers' DR actions have generated an observable benefit, this benefit could be monetized, and part of it should be used to incentivize demand-side participation. Currently, the peak and off-peak electricity price differences in the country are not significant enough to encourage a large number of customers to participate in DR. However, it is expected that with the influx of rooftop solar and the opening-up of the retail market to customers with demand less than 2 kW, the DR market is likely to grow above 50 MW by 2020, and will therefore require a review of the funding mechanism for Singapore's program.

Australia

The Australian pilot was funded by ARENA and AEMO outside the wholesale market. The RERT Trial used the California Independent System Operator (CAISO) "10 of 10" baseline methodology to define the baseline consumption of the proponents. To determine the baseline, AEMO used the proponent's aggregate customer consumption level as a portfolio. For specific loads, the pilot found that the method was not accurate and initiated a study of alternatives. The study results suggest that for loads which cannot be predicted by the "10 of 10" methodology, anchoring or control groups must be used. Anchoring involves establishing a baseline by assessing a facility's shape of consumption on the days with similar temperatures in the past, in the period before and in the period after the event day.

In the following section, we evaluate these lessons learned from international examples and develop recommendations to implement DR in Vietnam.

PART III:

RECOMMENDATIONS FOR DR PROGRAM IMPLEMENTATION

Chapter 11

Introduction

11 Introduction

The present section, Part III: Recommendations presents the results of Task 2.2 "Recommendations for improvement of DSM/DR program implementation".

11.1.1 Approach to developing recommendations

Our recommendations are structured around three key thematic areas: incentive-based DR programs, including the existing non-commercial CLP and EDRP; peak load electricity tariff program; and cross-cutting aspects. Each thematic area is then broken down into specific topics. The implementation of financial incentives for DR, such as direct financing incentives through CLP and EDRP programs, or peak load electricity tariff programs are critical in creating successful and sustainable DR programs.

For each sub-theme, we start with a review of the current state of play in Vietnam. Then, we review experience from other jurisdictions and comment on how these can be applied to answer the unique needs of Vietnam. Last, we formulate recommendations to address Vietnam's specific challenges. Recommendations are phased in time: short-term, medium term, and long term.

Some of the recommendations will require changes to the regulatory framework. The necessary changes to the regulatory framework are grouped together and presented in a separate chapter.

11.1.2 Overview of the recommendations

The following table provides an overview of the recommendations that are developed in the present report:

Topic	Recommendation	Time frame
Recommendations for Incentive-based DR Programs		
Short-term improvements to existing non-commercial programs	Continue efforts to encourage behavior change Technical and financial support to C&I customers in becoming more flexible Adopt a regional approach to triggering DR events Introduce regular Monitoring and Evaluation – Adjust program as needed	Short term
Commercial Incentive-based DR Programs	Introduce a two-part compensation mechanism (availability + utilization payments) Offer a variety of options to meet the needs of different types of customers Open DR programs to smaller customers	Long term Long term Long term
DR as an ancillary service	Examine the feasibility of treating DR as an ancillary service	Medium to Long term
Preparing the Terrain for the Aggregator Model	Conduct a pilot aggregator project on public funds Open the DR market to private aggregators	Medium term Long term

Topic	Recommendation	Time frame
Introducing competitively traded DR in the long term	Examine the possibility of competitively sourcing capacity-based DR Examine the relevance of trading DR on the wholesale energy market	Long term
Recommendations for Peak load electricity tariff program		
Selection of an adequate peak time tariff mechanism	Adopt critical peak pricing (CPP) for the peak time tariff program Progressively introduce Variable Peak Pricing (VPP) and Real-Time Pricing (RTP)	Short term Long term
Design of the peak-time tariff program	Conduct studies/surveys to understand customers preferences Determine the program's key parameters Adopt a progressive approach to implementation	Short term
Cross-cutting Recommendations		
Technological Readiness	Continuous monitoring and periodic assessment of the technology Eligibility of DR-enabling technologies for cost recovery Preparation of the switch from manual / local DR to automated / remotely controlled DR (Direct Load Control program)	Short, medium and long term
Capacity building	Ensure EVN and PCs have the necessary human resources to implement DR Ensure EVN and PCs can help C&I customers become active DR players Empower energy managers for commercial and industrial facilities with demand response training	Short term

Chapter 12

Recommendations for Incentive-based DR Programs

12 Recommendations for Incentive-based DR Programs

Chapter 2 presents recommendations for incentive-based DR programs. It starts with recommendation for the short-term that could help improve the outcomes of the existing programs. Then, it provides recommendations for the design of commercial incentive-based programs for the medium term, when it becomes possible. As an alternative, it explores the possibility of considering DR as an ancillary service, which could maybe help by-passing the current regulatory obstacles. Last, as a long term perspective, it discusses the development of aggregators and the introduction of competitively traded DR.

Short-term improvements to existing non-commercial programs

12.1.1 Current state of play in Vietnam

Today, Vietnam implements "non-commercial" DR programs targeting C&I customers. The term "non-commercial" refers to the fact the program is voluntary and customers do not receive financial compensation. In spite of the lack of financial incentive, significant results were already achieved in 2019: a maximum capacity reduction of 513.9MW (September 10, 2019), total electricity reduction of 6,373,302 kWh, resulting in savings of VND 24.12 billion (USD 1 million)[72]. But power sector players agree[73] that in the absence of financial mechanisms on electricity price and financial support to customers, the outcomes of DR programs will remain limited.

12.1.2 Recommendations

The question of financial incentives for customers who participate in DR programs is an important issue. The resolution of this issue may take time, up to several years. In the meantime, short term improvements could help the programs achieve better results. We have identified the following set of recommendations, meant to fix minor issues that were brought to our attention by stakeholders.

Recommendations: Short-term Improvements to Existing Programs	
Continue efforts to encourage behavior change	Short term
A campaign has already been conducted as a part of the country-wide roll-out of the DR program. However, according to stakeholders, utilities lack the means to sustain their efforts in awareness raising. Low-cost "nudges" could encourage behavior change, such as: - "Name and praise": Utilities publish a list of customers that responded the best to DR events, thus providing positive exposure to the best performers - "Peer comparison": Utilities provide C&I customers with information on how their own performance in DR programs compare to the average of their peers, thus encouraging customers to do better than the average	
Technical and financial support to C&I customers in becoming more flexible	Short term
Adopting DR requires that customers adapt their operations during peaks and/or invest in own generation or behind the meter storage. To do so, C&I customers need to understand their load profile	

[72] EVN Presentation of DR implementation in Vietnam, February 2020
[73] EVN Hanoi report to ERAV on DR implementation, February 2020

and power needs, identify physical (eg own generation) and non-physical (eg. adjust their operations during peak time) investments that could lead to a better management of their load. That support could be through technical support, energy management, and possibly financing instruments. A specific source of funding would have to be mobilized: at this stage we see two possibilities, either through the Science and Technology Development Fund, or with support from donors (the ADB for instance is interested in the development of an Energy Efficiency fund).	
Adopt a regional approach to triggering DR events	Short term
For 2020, EVN has provided an annual DR schedule with monthly events scheduled for the various regions with some small variabilities in peak times. Our understanding is that these events have been designed with a centralized view to support transmission congestion in the South. We recommend considering DR events also from a more decentralized stand, and possibly allowing PCs to schedule and trigger some DR events on a regional rather than national basis one. Adopting a regional approach to trigger DR events would increase the positive impact of DR relative to decongesting the local distribution systems.	
Introduce regular Monitoring and Evaluation – Adjust program as needed	Short term
In order to adjust existing programs, and to start building useful knowledge for the next stages of DR development in Vietnam, We understand that each PC already keeps track of the implementation of DR events and collects data on participation and actual load reduction. It is recommended to create an overarching, systematic Monitoring and Evaluation framework for these programs. The M&E framework would define indicators and fix targets against which actual results would be compared. The M&E data could be used to inform necessary adjustments to the program, and to advocate for the further development of DR in Vietnam	

Commercial Incentive-based DR Programs

In this section, we assume that necessary changes have been made (see Chapter 14) to allow PCs to offer financial incentives to participating customers. We discuss key lessons from international experience and key considerations for the design of financial incentives for commercial DR programs in Vietnam, envisaged as the continuation of the existing CLP and EDRP.

12.1.3 Current state of play in Vietnam

Vietnam's experience with incentive based programs is from the DR pilot program of 2015. It resulted in an average reduction of 4.75% of the peak demand among participating customers[74].

At that time, the following incentive was offered (expressed in USD for easier comparison with international experience):

	DR event occurring during		
	Normal hours	Off-peak hours	Peak hours
Compensation per kWh of curtailed demand – EDRP event (2h notice)	2 x tariff for normal hours	1 x tariff for off-peak hours	3 x tariff for peak hours
Application – Manufacturing customers, Voltage level from 6 kV to less than 22 kV	USD cents 13.9 /kWh	USD cents 4.5/kWh	USD cents 38.4/kWh

[74] EVN Presentation of DR implementation in Vietnam, February 2020

	DR event occurring during		
Compensation per kWh of curtailed demand – CLP event (planned)	tariff for normal hours	tariff for off-peak hours	tariff for peak hours
Application – Manufacturing customers, Voltage level from 6 kV to less than 22 kV	USD cents 7.0 /kWh	USD cents 4.5/kWh	USD cents 12.8/kWh

12.1.4 *Lessons from International Experience*

International experience examined in Task 2.1. Report provide a number of useful lessons when it comes to the design of these incentives.

12.1.4.1 *Basic Principles*

Obviously, the success of a DR program is greatly influenced by the level and structure of compensation. But the payment should not be higher than the value of DR to utilities, which is equivalent to their avoided costs[75]. In Vietnam, according to the outcomes of voluntary, non-commercial CLP and EDRP programs in 2019, these avoided costs are of approx. USD 0.15 per kWh of curtailed demand[76].

In order to establish the level of compensation, utilities and policy makers are guided by the following key questions:

1. What is the DR resource worth to the system?[77]
    a. Availability (or capacity): corresponds to the cost of the peaking plant should the system need this "additional" capacity
    b. Utilization (performance or energy): corresponds to the peak energy cost should the resource be dispatched at peak times for any length of time
2. Who pays for initial implementation costs and ongoing administrative expenses and incentives?
3. Will consumers participate at that price?

Is participation sufficient to warrant a program?

12.1.4.2 *Two-Part Compensation*

When demand response is mobilized and/or used as a resource to balance supply and demand as an alternative to generation for reliability or economic purposes, it is compensated in the various jurisdictions in a way that rewards participants for: (a) the availability of the resource with an "availability payment" ($/kW), and (b) its dispatch when called upon with a "performance-settlement, also known as utilization payment" ($/kWh). The availability payment is a fixed component while the utilization component is variable.

We understand that the incentive offered in the 2015 pilot DR program were only utilization based: customers were compensated only for the quantity of energy displaced during a DR event, but there was no availability payment. Based on international

[75] The value of avoided air emissions or the value of other externalities, such as avoided greenhouse gas emissions, may be included in these cost calculations.
[76] According to the numbers from EVN Presentation of DR implementation in Vietnam, February 2020
[77] Avoided externalities, such as air emissions are generally not monetized

experience, it appears that a two-part compensation mechanism could bring better results:

- An **availability payment ($/kW)** in exchange for being available to curtail. This payment is fixed. It is due even if no DR event takes place. Participating customers who receive this payment must commit to actually curtail during DR events, failing which some form of penalty applies. The commitment of participating customers is therefore stronger than under the 2015 DR pilot and the current non-commercial program in Vietnam.

- A **utilization payment ($/kWh)** when curtailed. This payment is due only when DR events occur. It is thus variable and depends on the load being curtailed and on the duration of the DR events. This payment is similar in nature to the incentive offered in the 2015 pilot DR program.

12.1.4.3 Design of Financial Incentives

To determine the right level of financial incentives, it is important to understand the electricity consumption patterns of the targeted customers, as well as their willingness to alter this pattern. In addition to typical load curves from various categories of C&I customers, information on their operations will help determine the kind of commitment that they are able to make, and the level of compensation that is adequate in exchange for that commitment. The level of incentive will also depend on the strength of the commitment from participating customers, and on whether the load is manually curtailed by the customer, or remotely controlled by the utility. As in incentive design for other programs, reaching the right incentive level may require an iterative process.

The table below gives examples of DR compensation from various jurisdictions (from Task 2.1 report). It includes both predetermined prices, fixed in advance by the utility or the regulator, and market-based prices determined by competition among DR providers:

Country	Availability payment (kW)	Utilization payment (kWh)
South Korea Negawatt reliability DR	Approximately USD 16/kW per month	Highest variable generation cost at that time
California Scheduled Load Reduction Program (SLRP)	None	USD 0.10 / kWh
California Base Interruptible Program (BIP)	8 to 9 USD/kW per month	None
California Capacity Bidding Program (CBP)	From USD 2.5 to USD 29/kW per month	None
Japan Negawatts market	Approximately USD 2 to 4 per month	TO BE CONFIRMED[78]
Hawaii C&I Direct Load Control (CIDLC)	$5 to $10 per kW per month	$0.50 per kWh
Hawaii Fast Demand Response	$25 to $50 per kW per month	$0.50 per kWh

[78] NOTE: we are in the process of verifying the numbers. Final numbers will be provided in the final report

Source: Econoler/CPCS Task 2.1 Report ; PG&E for California[79] ; Hawaiian Electric for Hawaii[80].

12.1.4.4 Need for a variety of options

The current experience with DR in Vietnam remains limited and as such, it may be difficult to predict accurately which DR option will be best suited to which type of customer. One way of addressing this uncertainty is to let customers choose from a variety of options in terms of:

- **Nature of the commitment** they are making: for instance, do they commit to respond to all DR events and are penalized if they don't, or do they keep some flexibility in their response? For now in Vietnam, response is on a voluntary basis only. Participating customers are not penalized if they fail to respond to a DR event
- **Duration and frequency of DR events**: how often is the utility allowed to trigger a DR event for this group of customers and how long do events last? For now in Vietnam, the number of DR events is defined in advance and is the same for all participating customers.
- **Notice period**: how much notice is given to participating customers before a DR event? For now in Vietnam, two options exist: 24h and 2h.
- **Direct control load**: whether the load curtailment is effected "manually" by the customer, or remotely controlled by the utility. For now in Vietnam, it is done manually by the customers, but a pilot Direct Control Program is envisaged[81].

Below is a description of current programs in Australia (from Task 2.1 Report). The design of the programs' action, duration, and frequency provide interesting comparators for Vietnam. It shows how a variety of options have been designed, offering more flexibility both for the participating customers and for the power system operator.

Program	Description
Critical price response	Flexibility is required at times when wholesale spot prices are high Action: Backup generator turns on within 10 minutes of notification Event duration: 30 minutes – 4 hours Event frequency: 10 – 15 hours per year
Frequency grid support (Ancillary DR)	Flexibility is required in response to brief, unexpected imbalances in grid supply and demand Action: Adjust equipment electricity usage or turn on backup generator within 60 seconds of notification Event duration: 4 – 10 minutes Event frequency: 6 - 20 events per year
Network support	Flexibility is required when grid stability is under threat within a distinct location, deferring expensive network upgrades Action: Adjust equipment electricity usage or turn on backup generator within unique network parameters

[79] Details on PG&E's demand response programs
[80] Demand response page on the utility's website
[81] Decision 175/QD-BCT dated Jan 28, 2019, cited in ERAV presentation of the DSM program dated June 2019

Program	Description
	Event duration and frequency: Unique to geographic location
Emergency grid support	Flexibility is required during emergencies that threaten grid stability Action: Adjust equipment electricity usage or turn on backup generator within 60 minutes of notification Event duration: 1 – 4 hours Event frequency: 0 – 10 events per year
Site peak shaving	Flexibility is required when electricity demand charges are calculated Action: Turn on backup generator within 1 minute of notification Event duration: 30 minutes – 2 hours Event frequency: 10 – 20 events per year
System peak shaving	Flexibility is required when system maximum demand is calculated Action: Adjust equipment electricity usage or turn on backup generator within 60 minutes of notification Event duration: 2.5 hours Event frequency: 6 – 10 times per year

Source: Econoler/CPCS, Task 2.1 report

12.1.4.5 Anticipating on the impact on PCs' revenues

DR may reduce the volume of kWh that PCs sell. As a result, successful DR programs could translate into loss of revenues for PCs. It has not been identified as a problem today, but it might become one in the future as DR grows. Eventually, this might create a counter-incentive for PCs, who would lose their motivation for implementing DR programs.

International experience offers interesting insights on how to make sure that distribution utilities' motivations remain aligned with DR targets. In Japan, utilities are compensated by aggregators for the loss of revenue caused by DR programs (see our Task 2.1 report: "Each aggregator uses a portion of this payment to compensate both the end consumer and the utility, since its revenue is decreased by the lowered power consumption"). Utilities can also be allowed to sell DR in the wholesale market with some form of profit margin, when DR becomes tradeable on the market. Last, if in the long term PCs become directly exposed to wholesale market prices (instead of buying power at a flat bulk tariff as is the case today), they will have a direct interest in reducing consumption through DR measures during high price periods.

12.1.4.6 Opening DR programs to smaller customers

Once incentive-based programs are successfully in place for C&I customers, participation could be opened to smaller loads. All jurisdictions have started with larger customers then have gradually moved to mass-market initiatives targeting small commercial and residential consumers. Large C&I customers are usually a lower hanging fruit for DR as they often have dedicated energy management staff which makes understanding of the program design and compensation terms, as well as participation and reduction, higher.

Once the full potential of DR with larger customers is realized, it will make sense to eventually expand to mass-market incentive-based DR programs. This could take the shape of curtailable load programs with e.g. A/C remote control with switch or smart thermostats. However, tapping into the DR potential of smaller customers will require aggregators (see Sections 12.1.8 to 12.1.10). Thanks to the widespread introduction of smart meters, price-based solutions (e.g. TOU + CPP) discussed in the next Chapter could be implemented as well for smaller loads.

12.1.5 Recommendations

Recommendations: Incentive-based DR Programs	
Introduce a two-part compensation mechanism (availability + utilization payments	Long term
The 2015 DR pilot offered an incentive based on energy (in kWh) curtailed during a DR event. Based on international experience, it appears that a two-part compensation mechanism could bring better results for commercial DR programs, including an availability payment ($/kW) in exchange for being available to curtail, plus a utilization payment ($/kWh) when curtailed.	
Offer a variety of options to meet the needs of different types of customers	Long term
As different customers will have different consumption patterns, offering a variety of options will allow more customers to find the right program for their specific needs. Options will differ in terms of the strength of the commitment made by customers, duration and frequency of DR events, notice period, and in the longer term the introduction of direct load control.	
Open DR programs to smaller customers	Long term
Once incentive-based programs are successfully in place for C&I customers, participation could be opened to smaller loads. This will require aggregators to be in place (see Sections 12.1.8to 12.1.10)	

DR as an ancillary service

In some jurisdictions, DR is considered an ancillary service. In Task 2.1 report we have listed:

- Interruptible load ancillary services program operated by NEMS in Singapore
- “Reliability and Emergency Reserve Trader (RERT)” operated by AEMO in Australia (pilot phase)
- PJM in the US East Coast allows DR resources to participate in the ancillary services market, as “Tier2 Synchronized Reserve Market”

In this section, we explore the feasibility of that kind of scheme in Vietnam. Since the financing of incentive-based programs poses a problem (see Sections 12.1.3 to 12.1.5), considering DR as an ancillary service could be a way of bypassing that problem: DR would be paid for by the system operator (NLDC) and recovered through the tariff[82].

12.1.6 Current state of play in Vietnam

We understand that the provision of ancillary services, also called auxiliary services or system services, is regulated by Circular 21. Ancillary services are defined as: “fast boot reserve, cold boot reserve, mandatory maintenance of electrical system security during power generation, frequency control and spinning reserves”. Circular 21 also regulates the compensation for ancillary services. The compensation paid by the system operator for some of these services is tied to the spot price on the VWEM, but there is no actual price-based competition for ancillary services.

12.1.7 Lessons from international experience and recommendatioin

As discussed in Task 2.1 Report, international experience shows that incorporating ancillary-based DR has proven rather successful. But in most jurisdictions, aggregators

[82] Ancillary services are eligible costs as provided for in Decision 24 “DECISION MECHANISM FOR ADJUSTMENT OF AVERAGE RETAIL ELECTRICITY PRICE” 24/2017/QD-TTg

are needed to act as intermediaries between the customers and the system operator. However, we do not recommended to introduce private aggregators in the short term – this is further developed in Sections 12.1.8 to 12.1.10 below.

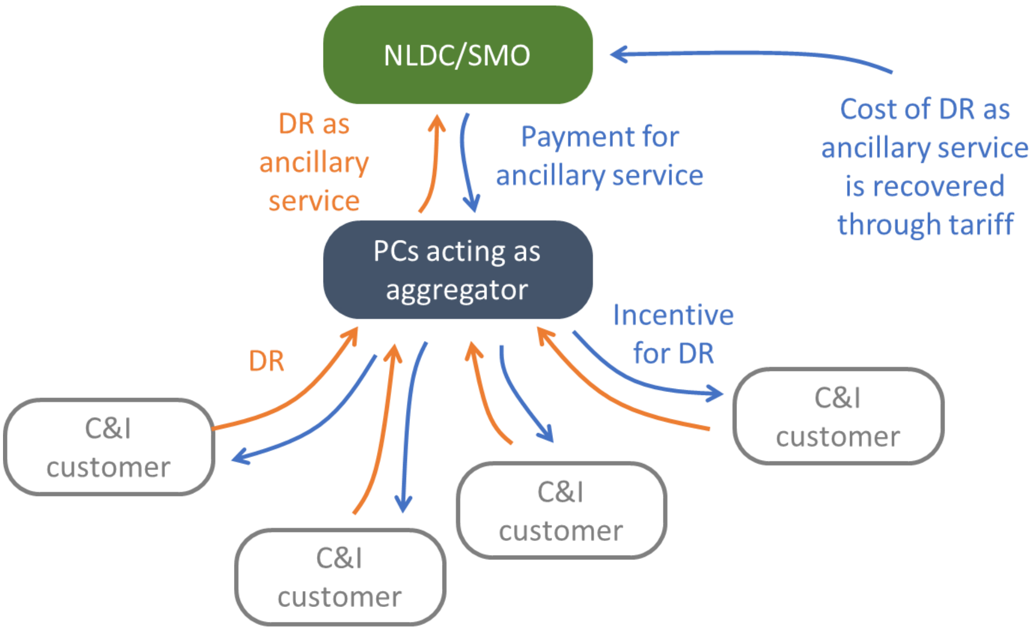
As an intermediate step, we suggest here that PCs could play the role of aggregators. The possibility of PCs acting as aggregator and selling DR as an ancillary service has already been envisioned by a preparatory study for the VWEM: “The main responsibilities of PCs in the VWEM [include] (…) Become Ancillary Services Provider (e.g. by providing interruptible load)”.[83]

In the short term, DR could be treated as an ancillary service as follows:

- PCs would pay an incentive to customers to provide DR services (very similar to incentive-based DR programs discussed above)
- PCs would sell aggregated DR as an ancillary service, and receive the corresponding remuneration from NLDC (SMO when created)

The costs to NLDC/SMO would be integrated in the tariff, as with other ancillary services.

Chart: Mechanism for treating DR as ancillary service with PCs acting as aggregators



Recommendations: DR as an ancillary service	
Examine the feasibility of treating DR as an ancillary service	Medium to Long term
Trading DR as an ancillary service, with PCs playing the role of aggregators in the beginning, offers an interesting avenue to bypass the key issue with incentive-based DR. This would however require amending the regulation. The feasibility of this scheme needs to be studied further.	

[83] TA 8851: Establishing the Vietnam Wholesale Electricity Market (VWEM), Task 2: Assessment of the current status of Power Corporations and recommendations for the implementation of new functions required for the VWEM. Ricardo for the ADB, March 2018

Preparing the Terrain for the Aggregator Model

12.1.8 Current state of play in Vietnam

Currently, participants in the DR model in Vietnam include: the customer, the utility and the system operator. But the aggregator model is identified in Decision 279 as a part of the DSM program. In addition, Decision 54 at Art. 4, paragraph 3, is also tailored to aggregators. A pilot aggregator project is included in the Implementation plan and roadmap for DSM (Decision 175) but to our knowledge, has not yet been implemented.

12.1.9 Lessons from international experience

The aggregator model is becoming the prevalent model, with large international players such as Italian ENEL with Enel X[84] (who operates in North America, several European countries, Australia and New Zealand), ITRON with Itron Distributed Energy Management[85], and Diamond Energy (in Singapore) to name a few.[86] It is used in many jurisdictions across the world. Aggregators act as an intermediary between customers and the utility / the power system operators / the wholesale market. Aggregators recruit customers to participate in DR programs, then sign a bilateral contract with the participant to compensate them for their load reductions. They then either bid the aggregate of these load reductions into the wholesale markets or contract with an electricity distribution utility for compensation.

The rationale for using aggregators is that, being specialized, they are able to develop better tools, skills and methods to encourage customers to join DR efforts. They are able to reach out to a large number of small / medium size customers who would not be interested in DR otherwise. In addition, many aggregators also offer load management advice to participants and help them better manage shifts in consumption and receive higher earnings from their DR resources. Aggregators also provide expertise and equipment to help participants to optimize their reduction with their operations.

Being private players and less subject to regulation than utilities, aggregators enjoy more freedom to create innovative compensation schemes for participating customers. They bundle and package demand response resources to best meet the operational requirements of the markets. They bundle customers into groups in order to diversify the risk of individual customers failing to curtail, as a result increasing the predictability and reliability of the resource. Aggregators also tailor different bundles of customer DR resources depending on whether the bundles will be bid for use as a capacity resource, as an energy resource, or as an ancillary service.

Thus, if the activity of aggregators is efficiently regulated and if the competition between them is healthy, a variety of efficient and adapted DR schemes will be available to customers. In turn, more customers will be willing to participate in DR, resulting in higher peak load reduction and savings for Vietnam's power system.

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[84] Formrly EnerNOC

[85] Formerly Comverge

[86] The impact aggregators can be seen in the rapid expansion of DR across the US in the past decade; between 2006 and 2012, reported potential peak reduction more than doubled, with the largest increases coming from wholesale customers, including third-party aggregators. In addition, relatively recently, these providers have spread to many countries across the world, from Europe to South Africa to New Zealand.

However, for these benefits to materialize, several preconditions are required. First, obviously, aggregators are private actors running a business. Some form of remuneration for DR must be available, either direct financial incentives offered by PCs, or through market trading of DR. Second, creating a healthy competition among aggregators requires an efficient regulation of their activity. To that end it is recommended that public players – first of which the regulator – already have accumulated some experience with commercial DR programs. If the framework for aggregators is poorly designed, it could result either in a lack of interest from private businesses, or in aggregators simply seeking to profit from the system without truly adding value to it.

For these reasons, we recommend introducing private aggregators only in the long term. A pilot aggregator project could however be envisioned in the shorter term, but it would have to be financed with public funds (possibly from the Science and Technology Development Fund) or with support from IFIs (possibly the WB-administered GCF Fund; USAID; GIZ).

Such a pilot would help the utility, the regulator, and the system operator start developing their experience as regards the role that aggregators could play in the future. Public-owned aggregators exist in other countries, for instance in Canada.

12.1.10 Recommendations

Recommendations: Preparing the Terrain for the Aggregator Model	
Conduct a pilot aggregator project on public funds	Medium term
The pilot aggregator would serve as an intermediary between C&I customers and a selected utility to implement existing non-commercial DR programs. If the ancillary market is opened to DR, the pilot aggregator could also provide DR to that market. The pilot could also be used to test other forms of DR programs (eg. with longer or shorter notice periods, increased or decreased frequency of DR events). The pilot will bring useful lessons as regards the kind of relationship that should be put in place in the future between the aggregators and the utilities, the system operator, and wholesale market players.	
Open the DR market to private aggregators	Long term
Aggregators should only be introduced once the appropriate market structure is in place, and after the stakeholders (utility and regulator) have acquired direct experience with DR, so that they are able to design and regulate the aggregator market.	

Introducing competitively traded DR in the long term

While incentive-based DR programs have been used for decades as an effective tool to manage peaks, there are issues surrounding the predetermination of various variables used to calculate compensation, in particular baselines and benefits. These ex ante calculations have resulted in compensation not always matching actual system benefits. With the introduction of market-based mechanisms, compensation is determined in real time based on actual system costs. Market-traded DR is thus an interesting option to ensure that compensations are fair and efficient.

12.1.11 Current state of play in Vietnam

Vietnam is in the process of implementing competitive markets for electricity. After a first phase under a single buyer model, since 2019, Vietnam Wholesale Electricity Market came in operation. The next phase of development will be the introduction of competition in retail, with the upcoming Vietnam Competitive Electricity Retail Market.

In other jurisdictions, DR is competitively traded on the wholesale market:

- Either on the **wholesale energy market** just like a power producer would, but with a price per kWh of curtailed demand instead of a price per kWh of generated electricity. In this case, DR is paid for by market players at market price;
- Or on the **market for ancillary services**, in a manner similar to reserve capacity. In this case the providers submit bids for kW of curtailable demand. DR is paid for by the system operator and recovered through the tariff.

The current design of VWEM does not allow for this for now: VWEM does not yet accept the trading of "negawatts", and ancillary services are not yet procured in a competitive manner. But this could become a possibility in the future, as VWEM evolves. The implementation would be dependent, though, on the operationalization of the wholesale market.

12.1.12 Lessons from international experience

International experience shows that competitively procuring ancillary-based DR (or capacity-based DR) has proven rather successful. On the other hand, trading DR on the energy market has been less successful. Studies[87] are indeed showing limited demand side resource participation in the energy wholesale market. In the case of Vietnam, two other obstacles would decrease the feasibility of energy-based DR trading: first, as noted above, the fact that the market rules do not allow demand-side participants as of now; second, the fact that the market price is for now capped. The current cap, at around USD 6 cents/kWh, is probably too low to be considered a meaningful incentive by prospective demand-side market players. Thus, market-traded DR on the wholesale energy market is not the preferred option, at least for now.

In jurisdictions that trade DR on the market, aggregators act as a mandatory intermediary between participating customers and the market or the system operator. Thus, the introduction of aggregators is another precondition.

Of note, should Vietnam decide to implement incentive-based DR programs, market-based DR can as in many other jurisdictions, such as California, PJM on the US East Coast, New England, and others, coexist with such programs.

12.1.13 Recommendations

Recommendations: Introducing competitively traded DR in the long term	
Examine the possibility of competitively sourcing capacity-based DR	Long term
This option could become relevant once Vietnam starts procuring ancillary services on a competitive basis, or develops a capacity market. DR providers would offer a price per kW of curtailable load for each time period.	
Examine the relevance of trading DR on the wholesale energy market	Long term
This option has not been the most successful across the world, but it should not be dismissed altogether. Its relevance should be examined in the medium to long term, once VWEM has reached a higher level of operationalization, and once aggregators are in place to serve as an intermediary between customers and the market.	

[87] Ibid

Chapter 13

Recommendations for Peak load electricity tariff program

13 Recommendations for Peak load electricity tariff program

Chapter 3 focuses on price-based mechanisms for DR. After presenting several options from international experience, we find that the best suited mechanism is Critical Peak Pricing (CPP), to be added to the existing Time of Use tariff (TOU). Recommendations are presented as regards the design of the program, the determination of the tariff, and its implementation on the ground.

Selection of an adequate peak time tariff mechanism

13.1.1 Current state of play in Vietnam

Today, all customers except residential customers are subject to time-of-use (TOU) energy tariff. Two important evolutions are envisioned[88] in the short term, with the view of incentivizing load management behaviour in customers:

- Introduction of a fixed capacity-based charge, per kW of subscribed capacity, in addition to the existing variable charge per kWh;
- Introduction of real-time peak time tariff, defined as follows: "The real-time peak tariff is a program with the electricity price table added to the electricity price component which increases steeply compared to the time-based electricity price index (TOU) during the peak time of the electricity system. This is to directly impact customers' electricity usage habits and encourage customers to proactively change electricity demand or reduce demand for electricity during peak hours of the electricity system"[89]

We understand that the introduction of a capacity charge is currently being studied by ERAV. In the present chapter, we will focus on the real-time peak time tariff and make recommendations for its design, based on international experience.

13.1.2 Lessons from international experience

Peak time tariff across the world take various forms that broadly fall into one of the three categories below:

13.1.2.1 Critical Peak Pricing (CPP)

Critical peak pricing (CPP) is a variation of TOU tariffs that adds a time-dependent rate several times higher than normal rate to either flat rates, or TOU rates, during critical peak periods. These additional cost needs to be high enough to induce participant response. A minimum ratio of 2.5 to 1 between critical peak and peak price level is recommended for US-based utilities. Critical peak pricing is only triggered for very specific events, such as system reliability or peak electricity market prices.

[88] As per Circular 23/2017/TT-BCT by the Ministry of Industry and Trade (MoIT) On Prescribing Contents and Processes for Implementation of Load Adjustment Programs
[89] Unofficial translation

13.1.2.2 Variable Peak Pricing (VPP)

Variable peak pricing, like the CPP rate, charges customers higher peak period rates for a predefined period. The main difference is the variability in this higher charge. While CPP relies on a fixed higher charge, VPP exposes customers to a variable peak price that fluctuates from one event day to the next in phase with market prices. In the absence of a DR event, the VPP rates acts as a regular TOU rate, with normal peak, off-peak, and shoulder period where applicable.

13.1.2.3 Real-Time Pricing (RTP)

Real-time pricing provides customers electricity prices in real time based on the hourly wholesale market price. Real-time prices reflect current conditions and provide a price signal based on the current marginal cost of power at a specific location. The customer has a price signal to reduce usage at times when cost is highest. Real-time pricing exposes customers to the variability and volatility of costs in the wholesale power market. The prices are provided to customers anywhere from an hour, to as much as 24 hours ahead of time and information can be sent to customers in various ways, including email, text, telephone, or an installed device.

13.1.3 Recommendations

Among these options, in the short term we recommend critical peak pricing (CPP) because it appears more adapted to the current status of Vietnam's power market, for the following reasons:

- CPP is a globally proven solution to incentivize peak load reduction;
- It offers a good level of predictability for customers since the tariff applied during peak events is known in advance. This is a good thing because C&I customers in Vietnam are not yet used to handling market price fluctuations. Exposing them to real-time market price variation could create confusion and results in customers dropping out of the scheme;
- Also, with VWEM's spot market price being capped for now, a tariff that is directly indexed on market price would be capped as well, thus possibly failing to send the powerful economic signal that is required for customers to reduce their load.

In the medium term, participants could be gradually exposed to wholesale market price. To that end, VPP could be implemented together with CPP, or replace it, or be offered to all with an opt-out option for customers who cannot take the price risk inherent to the wholesale market. In the long term, real-time pricing (RTP) can be introduced.

Recommendations: Selection of an adequate peak time tariff mechanism	
Adopt critical peak pricing (CPP) for the peak time tariff program	Short term
This option is proven internationally, and appears to be the best suited for Vietnam in the short term. In Sections 13.1.4 to 13.1.6 below, we will discuss the design of a CPP program	
Progressively introduce Variable Peak Pricing (VPP) and Real-Time Pricing (RTP)	Medium to Long term
In the medium term, participants could be gradually exposed to wholesale market price. VPP and RTP would then become relevant options.	

Design of the peak time tariff program

13.1.4 Current state of play in Vietnam

The introduction of a peak tariff program is already planned, with explicit references to it in official documents notably Circular 23 on load adjustment programs and Decision 28 on electricity tariff. Furthermore, with the ongoing deployment of smart meters, the application of peak time tariff should pose no problem from a technological perspective.

However, the details of a CPP program remain to be worked out. This will require the definition of a specific tariff-setting methodology, for which we provide recommendations below. It will also require to gather more information on customer's preferences and behaviour, in order to adequately fix the key parameters of the CPP.

13.1.5 Lessons from international experience

13.1.5.1 Key parameters for CPP design

In order to induce the desired demand response, there are key parameters that have to be taken into consideration when designing a CPP rate. EVN will have to make design choices around the following four variables[90]:

1. **Peak/Off-Peak Price Ratio**: What is the ratio of the price charged for peak period consumption compared to that charged for off-peak consumption?
2. **Peak Period Duration**: What is the timing and length of the period(s) where consumption is billed at a higher rate?
3. **Peak Period Frequency**: How often do the peak time periods occur?
4. **Number of Pricing Periods**: What is the TOU structure (number of daily periods, and number of distinct seasonal TOU rates)?

13.1.5.2 Peak to off-peak price (POPP) ratio

The peak to off-peak price (POPP) ratio is the leading indicator for reduction in peak demand. For TOU + CPP component, which is applied to a much smaller number of hours each year than the daily TOU peak rate, observed POPP ratios range from 4:1 to 20:1.[91] Based on literature accounts, a 5:1 ratio tends to result, on average, in about 14% peak reduction, and when this ratio is doubled at 10:1 a 16% reduction is observed.[92]

[90] Based on research from the Rocky Mountain Institute, *A Review of Alternative Rate Designs*, May 2016
[91] A. Faruqui and S. Sergici, *Arcturus: International Evidence on Dynamic Pricing*, The Electricity Journal, vol. 26 (August 2013)
[92] Ibid

Peak Reduction by POPP Ratio

13.1.5.3 Peak duration

Peak duration is the length of the period during which consumption is billed at a higher rate relative to other periods. The length of the peak period should be set to correlate with on-peak hours and hours where load reduction is desired in order to achieve system cost reductions or other objectives.

International experience shows that the duration of the peak price period has an impact on participation. If the peak period is too long, customers may be unable or reluctant to reduce consumption during the entire period. Customer surveys indicate a preference for a peak period duration not exceeding 4–5 hours, even if that means the peak price will increase.[93] To illustrate, one utility[94] found that predicted opt-in enrollment would drop by 25–50% if the peak period duration were extended from 3 hours to 6 hours. Across the world, studies have found critical peak periods during from 3 hours to 16 hours per event.

For the implementation of CPP in Vietnam, the duration for peak pricing should be directly linked with actual system peak, based on load curve analysis. Based on available data[95] the duration of the system peak is in the range of 2 to 4 hours, which is in line with what international experience tells us of customers' preferences.

13.1.5.4 Peak period frequency

Peak period frequency relates to how often peak periods or events occur. For CPP rates, participation levels may decline if too many critical peak events are allowed. While TOU rates have peak periods that occur regularly, usually on a daily basis (excluding

[93]J. M. Potter, S. S. George, and L. R. Jimenez, "*SmartPricing Options Final Evaluation*," Sacramento Municipal
Utility District (September 2014).
[94] Sacramento Municipal Utility District (SMUD)
[95] Typical daily load curve, as communicated to the Consultant in September 2020

weekends), CPP rates usually limit the number of peak events at 5–22 days per year.[96] That said, utilities have struggled to accurately predict critical peak events for targeting system peak.[97] So while too many critical peaks may negatively impact participation levels, too few peaks may also miss the actual system peaks. If too low, increasing the annual number of critical peak events could be considered. The right balance, not too many or too few CPP events, is a matter of trial and error. ERAV and EVN have to work together to reach a suitable balance.

13.1.5.5 Number of pricing periods

Number of pricing periods is the number periods within 24 hours in each season (if they are seasonal) with distinct price levels, to reflect variation in system costs. CPP is overlaid on top of TOU rates. Most utilities have between 2 to 4 TOU daily periods, and 2 to 4 seasons. In order for consumers not too become fatigued or confused with too many time periods and then not participate in the CPP events, enabling technology needs to be available.

13.1.6 Recommendations

13.1.6.1 Indications for the determination of key parameters

The table below provides some indication as regards the determination of the key parameters, based on international experience and Vietnam's experience.

Indications for the determination of key parameters for CPP

Key parameter	**Vietnam's experience**	**Indication from international experience**
Peak to off-peak price (POPP) ratio	The current POPP of Vietnam's TOU is 1.8 for manufacturing sector and 1.7 for businesses[98] In the 2015 DR pilot, the POPP (considering the compensation paid per kWh of curtailed load) was about 8.	Observed POPP ratios range from 4:1 to 20:1. Higher POPP lead to bigger peak reduction but lower participation. ⇨ The range from 5:1 to 10:1 could be a reasonable starting point for Vietnam.
Peak duration	The duration of DR events under the CLP and EDRP programs is 2 hours	Customer surveys indicate a preference for duration not exceeding 4–5 hours. This is in line with observed system peak duration in Vietnam. ⇨ Duration of 2 to 4 hours could be a reasonable starting point for Vietnam.
Peak period frequency	In 2019, EVN has implemented 10 DR events	CPP rates usually limit the number of peak events at 5–22 days per year. ⇨ 10 to 20 events a year could be a reasonable starting point for Vietnam.
Number of pricing periods	TOU tariffs have 3 different periods, and no seasonality.	Most utilities have between 2 to 4 TOU daily periods, and 2 to 4 seasons ⇨ Seasonal tariffs are probably not relevant in Vietnam.

[96] Rocky Mountain Institute, *A Review of Alternative Rate Designs*, May 2016
[97] For example, from 2009–2011, 42% of events called by PG&E's SmartDays program did not align with system peak days.
[98] Ratio between

	⇨ Regional variations to tariff or to peak periods could be envisaged.

13.1.6.2 Understanding customers preferences

It is important to form an accurate understanding of the relationship between the peak to off-peak price (POPP) ratio and the corresponding demand reduction, and possibly adjust the POPP ratio to improve responsiveness and levels of reduction. An initial step would be to survey would-be participants to reveal their preferences, and base the initial design of the CPP on the results of the survey. Later on, when the CPP is implemented, the key parameters of the program can be adjusted based on the program's outcome in terms of participation and actual demand reduction.

We also recommend that the program be designed in such a way that C&I customers billed under CPP can actually save on their bills if they manage their peak load properly. Thus, CPP will provide a financial incentive for C&I customers to invest in load management solutions. To make the program attractive, participating customers could receive a rebate on their off-peak hours consumption for instance. This will require a good understanding of customers' load curves and ability to implement load reduction.

We note that ERAV has had some exposure to Singapore's DR implementation: NEMS may be a useful resource for ERAV in this process. Also, we note that a study is currently under way with the support of the ADB to determine the potential for DR among various categories of customers. This study will provide insights as regards customer's expected behavior.

13.1.6.3 Eligibility and enrolment

Eligibility defines which customers can participate in the program. Based on experience, the recommendation is to start with larger industrial/manufacturing customers and expand progressively to medium and small C&I customers. In Vietnam, CPP should first target the Designated Energy Users (DEU – also refered to as Key Energy Users or KEU).

To enroll eligible customers in the CPP program, three options can be considered:

- Opt-in: eligible customers decide to opt-in if they want;
- Opt-out: TOU+CPP becomes the default option for all customers in one given category, but with option to revert back to traditional TOU;
- Mandatory for all customers in one given category.

If CPP is not mandatory, customers may be hesitant at first to go for CPP. The following approach could be tested[99]: after one year of CPP billing, the utility will simulate what "traditional" billing would have been for the customer and will compare it with CPP billing. If "traditional" billing would have been lower, the customer can opt out of CPP.

13.1.6.4 Progressive approach to implementation

We recommend a progressive approach to implementation so that customers have time to adapt to the CPP, and PCs/ERAV have time to adjust rate design according to uptake by customers and impact on peak load.

[99] Inspired from the peak-time tariff program in California.

It is important to note that even within one given category, not all customers have the same ability to manage their load, nor the same sensitivity to price signals. Thus, two or three different CPP options, with varying levels of peak tariff, should be offered to eligible customers. After one or two years, based on information gathered through the monitoring process, it can be decided to remove some of the options if the uptake and/or impact is low.

One last important point regards customers' education. The best way to truly educate customers is to increase the peak tariff progressively and inform customers that prices will continue increasing. Customers receive a "price trend signal" rather than the traditional "price signal". This way, customers will start noticing, be aware that they need to modify their habits during peak time, and start making the required investments in load management systems. This progressive approach may be more successful than a sudden increase in peak tariff.

Recommendations: Design of the peak-time tariff program	
Conduct studies/surveys to understand customers preferences	Short term
It is important to anchor the initial design of the CPP on a precise understanding of the customers' load curves and consumption patterns and of their ability to adapt their consumption in response to price signals.	
Determine the program's key parameters	Short term
The CPP design comprises of the following key parameters: Peak to off-peak price (POPP) ratio, Peak duration, Peak period frequency, Number of pricing periods, Eligibility and enrolment. We have provided indications based on international experience to help with the determination of these parameters	
Adopt a progressive approach to implementation	Short term
We recommend a progressive approach to implementation so that customers have time to adapt to the CPP, and PCs/ERAV have time to adjust rate design according to uptake by customers and impact on peak load. A pilot phase is recommended (see Chapter 17 below)	

Chapter 14

Necessary changes to the framework

14 Necessary changes to the framework

Chapter 4 proposes an initial, high-level identification of the changes to will have to be introduced in the regulatory framework before implementing the recommendations proposed in Chapters 2 and 3, namely:

- Commercial CLP and EDRP;
- DR as an ancillary service;
- Competitively traded DR;
- Peak time tariff

Framework for commercial CLP and EDRP

Within the existing framework, PCs are not entitled to recover the costs of CLP and EDRP in the tariff. This, in turn, directly impacts their ability to offer adequate financial incentives to customers participating in CLP and EDRP.

Indeed, DR costs are not direct expenses related to the generation, transmission and distribution of electricity. Therefore, they are not explicitly eligible for cost recovery through tariff. This point has been the object of exchanges between ERAV/MOIT and MOF for several years. The most recent correspondence on this issue is formed of MOIT letter dated December 31, 31 (Letter 10192 /BCT-TKNL) and MOF response dated March 27, 2020 (Letter 3609/BTC-TCDN). In their answer, MOF recommend that MOIT takes its case to the Commission for the Management of State Capital and Enterprises (CMSC) to study and clarify the definition of what constitutes a direct expense.

A discussion on the regulation of State enterprises in Vietnam is unfortunately outside of the scope of the present study. We have identified however, two other avenues that could contribute to resolving the issue:

1. **Compensating DR through a preferential tariff** rather than with direct incentives. Instead of being paid for curtailed load during a DR event, customers who reduce their consumption would be offered a more attractive tariff outside of DR events. Thus, DR would translate into a reduction of revenue for PCs rather than an expenditure. This could be a solution to bypass the major issue noted above. Such a scheme, though somehow similar to a Peak Time Rebate[100], is not yet proven in other jurisdictions to our knowledge. We are therefore not in a position to recommend it, but it could be studied further if found relevant by the stakeholders.

2. **Treating DR as an ancillary service**, as proposed in Sections 12.1.6 to 12.1.7. Ancillary services are paid by NLDC and the corresponding costs are recovered through the tariff. This is already tested in other jurisdictions (Singapore, Australia). We propose in the next section a high-level identification of the changes that would be required in terms of regulatory framework.

[100] Under California's Peak Time Rebate, customers who reduce their consumption during peak events earn rebates on their bill. See for instance PG&E's website.

Framework for DR as an ancillary service

The fact that DR can contribute to the provision of ancillary services is already identified in MOIT Decision 175/QD-BCT *Approving the implementation plan and roadmap for the DR Program*: "Implement the DR Program as a Virtual Power Plant (VPP) model, provide ancillary services for the power system and market operation".

Ancillary services are chiefly regulated by MOIT Circular 21/2015/TT-BCT *On regulating the pricing method for electric power system's ancillary services and the procedure for scrutinizing a contract for provision of electric power system's ancillary services*. To allow for DR to be treated as an ancillary service, the following changes would have to be made:

- Include DR in the list of ancillary services;
- Include PCs and aggregators in the definition of "Provider of ancillary services"
- Define the method for pricing

It might also be needed to slightly amend the tariff calculation formula in PM Decision 24/2017/QD-TTg *Mechanism for adjustment of average retail electricity price*. The current restrictive wording "power plants providing ancillary services" should be replaced by "payments to providers of ancillary services".

Should the stakeholders decide to pursue this option, the feasibility should be further examined, both from a regulatory and operational perspective.

Framework for competitively traded DR

Competitively traded DR, as outlined in Sections 12.1.11 to 12.1.13, would require several important changes to the framework.

For DR to be traded on the wholesale energy market, market rules would first have to be amended to allow demand-side players to sell "negawatts". It is also likely that with the current cap on peak prices, selling DR on the energy market would not be attractive. Thus, the cap should be increased, or lifted altogether.

For DR to be competitively procured as an ancillary service or on a capacity market, such a market would first need to be developed. Today, the compensation paid by the system operator for some ancillary services is tied to the spot price on the VWEM, but there is no actual price-based competition for ancillary services. And, as far as we are aware, there is no plan to establish a capacity market in Vietnam.

Framework for peak time tariff

The possibility of introducing peak time tariff is already mentioned in PM Decision 28/2014/QD-TTg *Regulations on structure of electricity retail tariff* : "The Ministry of Industry and Trade shall (...) study (...) incentive mechanism of electricity price for pilot application for customers participating in the program of electricity demand management".

Chapter 15

Cross-cutting Recommendations

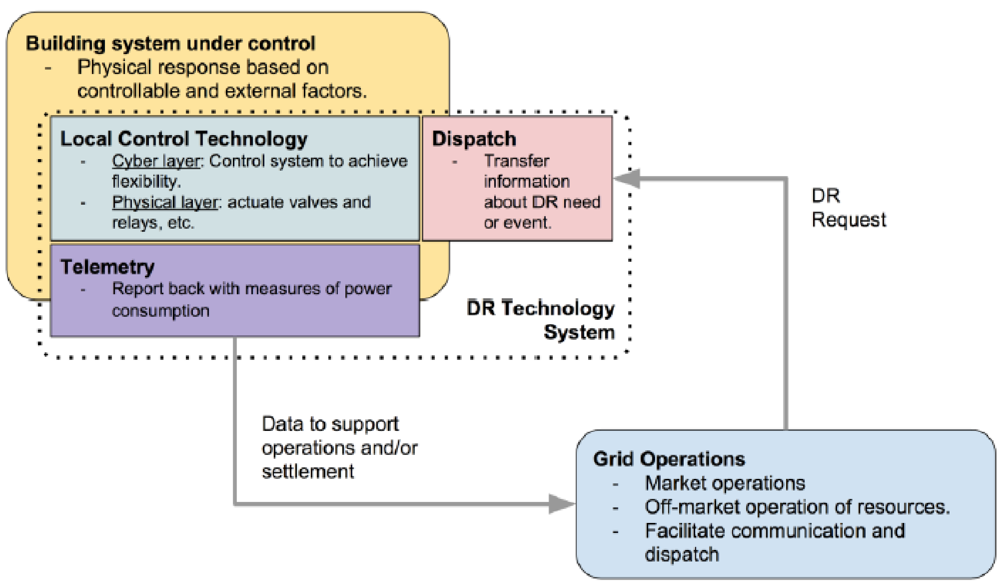
15 Cross-cutting Recommendations

Chapter 5 covers cross-cutting subjects that will have to be addressed independently of the details of the programs that are eventually implemented. The following recommendations would apply for all demand response options, be it incentive-based, bilateral price-based or market-based.

Technological Readiness

Demand response rests on technology; it is a crucial element to enable DR. A demand response enabling technology consists of the mix of load control and communications hardware and software that makes loads flexible. There are several components that need to come together, with specific technological devices, instruments and software, needed on the customer's end, and on the utility and the system operator sides. The figure below represents a schematic of the interactions between the DR technology system (dotted area) found on the utility's end, the customer ("building systems under control" in yellow) and the system operator.

Figure: Technological Interactions between the Utility, the Customer and the System Operator.[101]



Source: Berkeley Lab (2016)[102]

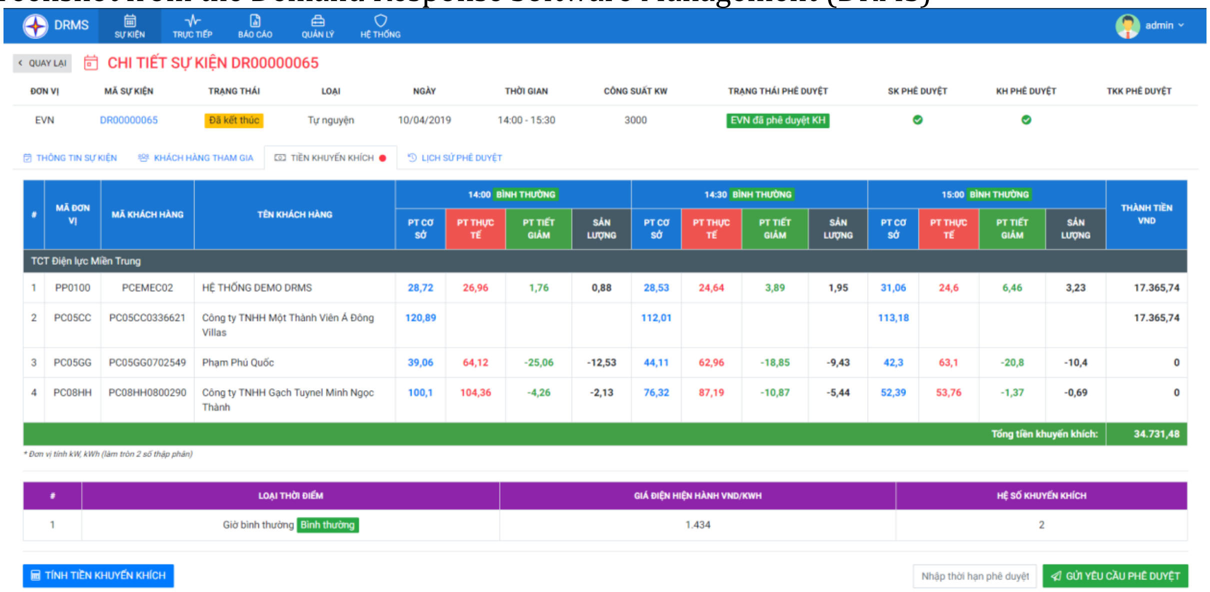
15.1.1 Current state of play in Vietnam

In Vietnam, the system operator NLDC is part of the vertically integrated utility EVN. The country's system operator has already developed and rolled-out a specialized software to communicate with the five distributors: the Demand Response Software Management (DRMS). All large customers are equipped with electronic meters that share consumption data with EVN

[101] The dotted area represents the behaviors considered in DR-PATH.
[102] Berkeley Lab, *2016 California Demand Response Potential Study,* (April 2016)

at 15-minutes intervals. Smart meters are currently being rolled out for the entire country. By 2021, it is planned that all customers will have a smart meter.

Screenshot from the Demand Response Software Management (DRMS)



Source: EVN presentation, 2019

It can thus be said that the technology in place in Vietnam is adequate for the DR programs that are being implemented now. Looking forward however, technology will have to evolve as DR programs become more sophisticated and target a larger, more diversified customer base. This issue is already identified in Vietnam's Implementation plan and roadmap for the DR Program. In the section below, we highlight the most important aspects of technological readiness based on international experience.

15.1.2 Lessons from international experience

The figure below illustrates the various technologies that are necessary to enable DR. We have kept the residential end uses as Vietnam may soon decide to pilot such initiatives as well.

Figure: Summary of DR Uses by Customer Segment and Corresponding Enabling Technology in California[103]

[103] Berkeley Lab, *2025 California Demand Response Potential Study*, (March 2017)

Sector	End Use	Enabling Technology Summary
All	Battery-electric and plug-in hybrid vehicles	Level 1 and Level 2 charging interruption
	Behind-the-meter batteries	Automated DR (Auto-DR)
Residential	Air conditioning	Direct load control (DLC) and Smart communicating thermostats (Smart T-Stats)
	Pool pumps	DLC
Commercial	HVAC	Depending on site size, energy management system Auto-DR, DLC, and/or Smart T-Stats
	Lighting	A range of luminaire-level, zonal and standard control options
	Refrigerated warehouses	Auto-DR
Industrial	Processes and large facilities	Automated and manual load shedding and process interruption
	Agricultural pumping	Manual, DLC, and Auto-DR
	Data centers	Manual DR
	Wastewater treatment and pumping	Automated and manual DR

Source: Berkeley Lab (2017)

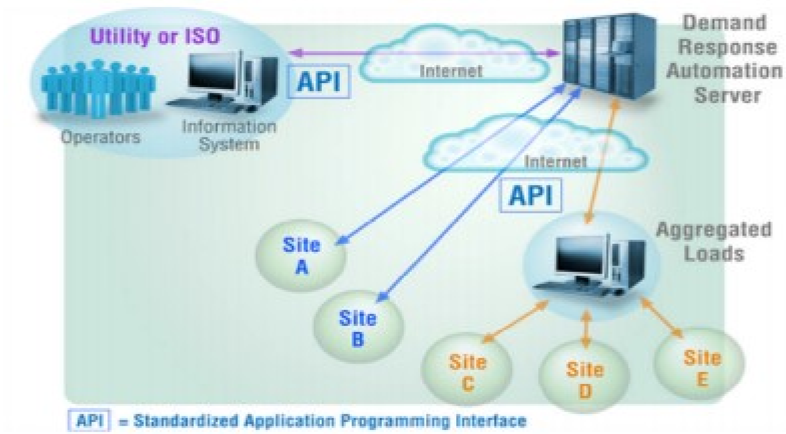
15.1.2.1 Technologies to advance demand response strategy development for large customers

Technology can help large customers become active DR players. In California, in the commercial sector, a few years ago, the California-based Demand Response Research Center (DRRC) developed the Demand Response Quick Assessment Tool (DRQAT) to advance demand response strategy development for large commercial buildings. This tool is built on simulation software. It incorporates prototypical buildings and equipment and allows users to specify a relatively small number of important parameters, such as building materials and size, equipment, and utility rates, to conduct a quick assessment of demand response strategies that utilize building thermal mass.

15.1.2.2 Shift from "manual" to "automated" DR

We understand that today, customers in Vietnam respond "manually" to DR events: they adjust their load themselves through several notifications and decision steps. As DR becomes more mainstream, a larger topic relates to the development of more automation for demand response and the technology upgrades and shifts that this may result in. A number of leading jurisdictions are currently analyzing the potential for a more automated response" or "auto DR". Auto DR relies on the availability of instantaneous communications and the internet of things (IOT) to offer DR solutions. Automation will help simplify communication during the event, which should lead to faster reaction times and more reliable participation. This is of particular relevance for the proposed "Direct Load Control program" as per Decision 175[104].

[104] Decision 175/QD-BCT dated Jan 28, 2019



Source: OpenADR Alliance

15.1.2.3 Technologies for the residential mass-market

In the longer term, when Vietnam starts developing DR for the residential market, technological readiness will also be a crucial issue. In Canada and the US in the residential mass-market for DR, air conditioning direct load control programs were initially based on simple switches. These were replaced gradually with programmable thermostat or other 2-way communication platforms (gateway technologies). Similarly, advanced metering and AMR technologies (automated meter reading) can be used both to control equipment and to incorporate innovative pricing options. In addition, this technology can be used to provide synergies where thermostats are adjusted during periods in which prices are high, thereby providing customers with additional benefits.

As the residential mass-market is not in the scope of the present study, this point is mentioned for the record only and has not been included in our recommendations below.

15.1.3 Recommendations

The following table present a set of recommendations for Vietnam as regards technological readiness.

Recommendations: Technological Readiness	
Continuous monitoring and periodic assessment of the technology	Short and medium term
DR resources portfolios will need periodic assessment and transition plans to address changes in technology, in particular in the context of the switch from manual DR to automated DR that we are currently observing and that may arrive very fast to Vietnam potentially bypassing some of the manual DR technological requirements. Vietnam should closely monitor the technological requirements associated with automated DR so as not to waste monies investing in programmed obsolescence.	
Eligibility of DR-enabling technologies for cost recovery	Medium and long term
The regulator has an important role to play as regards cost recovery. The regulator may have to weigh in as regards expenses associated with technological advances and software development, as the technological advances are fast moving.	
Preparation of the switch from manual / local DR to automated / remotely controlled DR (Direct Load Control program)	Medium and long term

As DR becomes more mainstream, a larger topic relates to the development of more automation for demand response and the technology upgrades and shifts that this may result in. Automation will help simplify communication during DR events, which should lead to faster reaction times and more reliable participation.

Capacity building

15.1.4 Current state of play in Vietnam

We understand that players in charge of implementing DR, first of which EVN and PCs, have already developed their capacity to implement DR. We however gather from interviews with stakeholders that the existing capacity may not be sufficient as DR programs expand in the near future. We also understand that there have not been specific initiatives to build the capacity of customers enrolled in DR programs, to help them build their capacity to react to DR events.

15.1.5 Recommendations

Recommendations: Capacity building	
Ensure EVN and PCs have the necessary human resources to implement DR	Short term
Expanded staffing in the area of demand response should be planned and mapped in accordance with the sophistication and wide-spread use of demand response.	
Ensure EVN and PCs can help C&I customers become active DR players	Short term
It is important that power utilities can support participating customers in understanding how they can participate in DR without hampering their operations. So, EVN and PC staff should be in sufficient number and trained to help C&I consumers with appropriate load management plans to achieve government mandated DR targets.	
Empower energy managers for commercial and industrial facilities with demand response training	Short term
As soon as feasible, we recommend adding one or more modules specifically on demand response to formalize demand response training as part of Circular 39/2011/TT-BCT "Providing for training, grant of certificates of energy management and energy auditors". Below is a description of the current content for this certificate and 3 recommended modules:	

Figure: Energy Manager Training Content

Module No	Description	Days
Existing modules		
1.	*Legal Responsibilities of KEUES*	*1st day*
2.	*Energy Management and Energy Management System*	*1st day*
3.	*Energy Efficiency Project Management*	*2nd day*
4.	*Energy Flow and Energy Loss*	*3rd day*
5.	*Energy Efficiency and Conservation in Lighting system*	*3rd day*
6.	*Energy Efficiency and Conservation in Electrical Utilities*	*3rd day*
7.	*Pump, fan and compressed air systems*	*4rd day*
8.	*Air conditioning and industrial refrigeration systems*	*4rd day*
9.	*Industrial Steam Systems*	*5th day*
10.	*The Certification Exam*	*5th day*
Recommended supplemental modules for DR		

11.	**Introduction to Demand Response**	**Recommended, one day training**
12.	**Integrating Available Demand Response Solutions into your Operations**	**Recommended, one day training**

As new DR options and programs are introduced in the medium and long term (eg. DR trading in the Vietnamese Wholesale Market), the training should be adapted to reflect these evolutions.

Long-term Planning for DR: Continuous Feedback, Monitoring, and Integrating DR in Resource Planning

15.1.6 Current state of play in Vietnam

The targets for peak reduction through DR are fixed by MOIT Decision 175[105]: 90 MW by 2020, 300 MW by 2025 and 600 MW by 2030. Circular 23, Chapter IV "Supervision, assessment and reporting of results of implementation of load adjustment programs" defines the mechanisms by which DR programs are monitored.

We note that the reporting mechanisms are mostly geared towards measuring actual load reduction and comparing with the target. From our understanding, the reporting mechanisms do not include monitoring customers' preferences and collecting their feedback. This is probably an aspect that could be developed in the coming years.

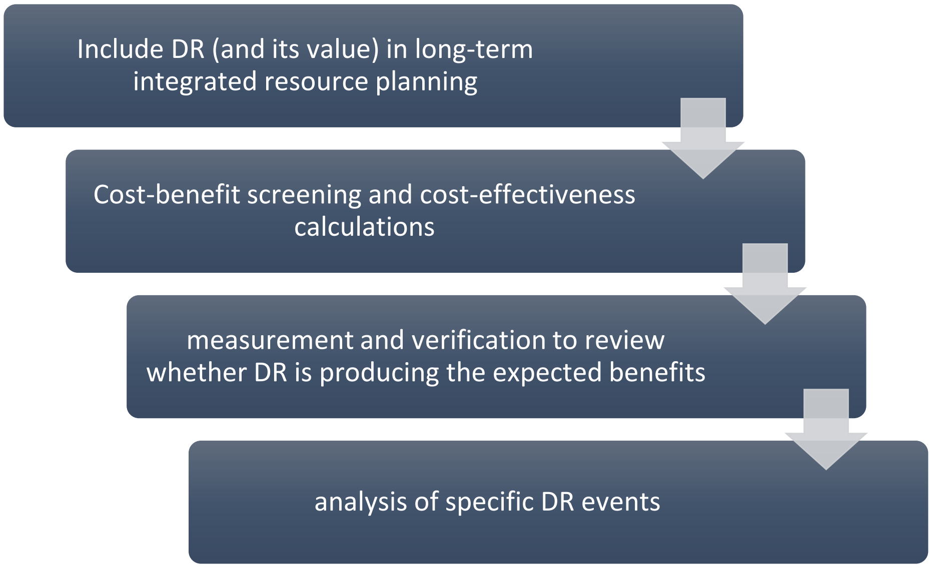
More generally, as DR is further developed, it will become an integral component of the power system and as such, will have to be integrated in long-term planning.

15.1.7 Lessons learned from international experience

In order to make the most of DR in the long term, a comprehensive planning framework would include the following elements:

[105] MOIT Decision 175/QD-BCT Approving the implementation plan and roadmap for the DR Program. January 28, 2019

DR Comprehensive Framework and Lifecycle



Step 1: Integrated Resource Planning

In the context of the development of the Integrated Resources Plan (IRP), the value of the various DR options is assessed over the horizon of the integrated resource plan, highlighting the value over the short, medium and long term (i.e. 3-5 years; 5-10 years; and 10-20 years or however long is the planning horizon). Although certain options may not be feasible in the short run, they should be included in the IRP horizon.

In addition to the value of DR and its impact in displacing peaking generation, the integrated resource plan should include how DR will explicitly alleviate transmission constraints, but also distribution constraints, as well as help mitigate the variability of renewable generation.

Step 2: Cost-benefit Evaluation and Cost-effectiveness Calculations

Since DR is valued largely on the basis of avoided costs in comparison to supply side resources, an ex-ante cost-benefit analysis ensures that all design and implementation elements are appropriately considered. Also, a cost-effectiveness analysis should provide metrics to quantify instances where DR resources are applied when more economical than supply side resources.

Of note, specific recommendations regarding CBA will be provided in our Final Report.

Step 3: Impact Evaluation, and Measurement and Verification

Evaluation, and Measurement and Verification (EM&V) is necessary to review whether DR is producing the intended benefits. Integrated resource planning and CBA /cost-effectiveness are prospective assessments and forecast the value of DR under selected planning assumptions. Decision 54 provides the methodology for baseline calculation, however not the measurement and verification protocol. Ex post analysis using M&V protocols[106] will help assess the overall

[106] M&V methods were discussed in the Task 2.1 Report. The day-matching method was the simplest approach.

value of DR solutions did bring, but also help refine and recommend changes to the DR solutions portfolio.

Step 4: Analysis of specific DR events

DR events will in and of themselves be the best guide to tailor DR solutions over time. If it has not been done yet, we suggest that ERAV mandate EVN to collect event related information and analyze this material. There are many variables, such as participation levels, types of industries and businesses who participate, level of reduction, level of peak to off peak ratios, elasticities, etc. that need to be collected to improve the DR solutions offered, and introduce new ones. With respect to participation levels (and elasticities), revealing consumer preferences can be difficult, we would therefore recommend that ERAV or EVN create focus groups in the various regions with large commercial and industrial customers to collect feedback on their preferences and experiences with current DR options so as to map future actions, and adjust important variables such as the peak to non-peak price ratios.

15.1.8 Recommendation

Recommendation: Long term planning	
Set up a comprehensive framework for planning and monitoring of DR	Medium term
As DR grows, the current planning and monitoring processes should be expanded into a comprehensive framework, covering Integrated Resource Planning; Cost-benefit Evaluation and Cost-effectiveness Calculations; Evaluation, and Measurement and Verification (EM&V); and Analysis of specific DR events.	

Chapter

16

COST BENEFIT ANALYSIS METHODOLOGY

16 Cost Benefit Analysis Methodology

16.1 Cost benefit analysis instrument

The objective of this chapter is to develop a framework for assessing the costs and benefits of a demand response programs that can be used by ERAV, MOIT and other stakeholders. It should be noted that there is not a single framework for this purpose, and most of the existing cost-effectiveness or cost-benefit analysis tools for demand response measures were adapted from those designed to evaluate energy efficiency and demand-side management programs. These screening tools have not been significantly modified or expanded to handle details specific to demand response programs, however. Further, the valuation of the benefits associated with demand response programs can be challenging, depending on the program offerings.

Because there are numerous demand response program types designed to serve different purposes, this discussion focuses specifically on the types of demand response programs that are administered and funded by electric utilities.[107] While it is understood that ERAV is interested in the wholesale market model, it is also understood that the development of this market may take some time, and will require changes in regulations before those conditions can exist. Therefore, the discussion below offers only the framework for evaluating the cost-effectiveness of utility (or self-funded) demand response programs. It does not cover those demand response programs that are offered by, or in organized wholesale electricity markets, as the same framework may not apply.

The survey that was conducted on international DR programs also served as the input for this chapter. Several jurisdictions were reviewed with respect to the cost-effectiveness frameworks being applied for their DR programs. The California DR protocols appear to be the most complete and adaptable framework developed. Therefore, it is recommended that ERAV consider using the California framework as the foundation for its own DR cost-effectiveness analysis framework.[108] Specifically, the California Public Utility Commission (CPUC) investigated the appropriate frameworks for screening the cost-effectiveness of California's demand response programs since 2007, and has developed and adopted a method for estimating the cost-effectiveness of most demand response activities.[109] A number of other jurisdictions have developed their own approach based on the CPUC's, including the US Pacific Northwest, Canada's Ontario Province, and others.

The California cost-effectiveness analysis framework can be applied to price-based and incentive-based program options listed in the table below. Simply stated, the framework provides utilities and regulators with a consistent methodology to quantify the program

[107] "Utilities" as used in this context refers to the electricity provider, which can include public power agencies, municipal utilities, and cooperatives.
[108] Note that the smart grid cost-effectiveness frameworks used by US DOE rely upon the California SPM framework, indicating that ERAV can continue to use the adapted framework in the future.
[109] California Public Utilities Commission, "Demand Response Cost-Effectiveness Protocols". December 21, 2010.

benefits and costs in order to compare them. By applying a consistent cost-effectiveness framework across the different types of programs (incentive or price-based), it will allow for a more balanced comparison. Further, the framework for the below program options should be of interest to utilities and regulators like ERAV, because they have the responsibility to ensure that the benefits of such programs outweigh the costs.

Table 4: DR Program options for cost benefit analysis

Price based DR program options[110]	**Incentive based DR program options**
Time of Use Rates	Direct Load Control
Real Time Pricing	Demand Bidding/Buyback
Critical Peak Pricing	Interruptible/Curtailable Load
Peak Time Rebates	

16.1.1 Quantification of Costs for Price-Based and Incentive-Based Programs

There are many different types of costs that must be accounted for when evaluating DR program cost-effectiveness, each of the costs is discussed in more detail in the sections below (not all programs will incur every cost listed). Note: examples of incentives and availability payment levels are available in Part II.

- Program Administration: These include the operations and maintenance costs, program costs, information technology expenses, DR system operation and communication costs, marketing and outreach costs, as well as any evaluation, measurement, verification (EM&V) costs associated with the program.[111]

- Program Administration Capital Costs: These include the costs incurred for equipment with relatively long lives, such as information technology equipment, communications technologies, and demand control technologies. Program administration capital costs include the costs for equipment installed to support the program administrator but not participating customers.

- Financial Incentive to Participant: If the program provides participating customers with a direct financial incentive to modify their electricity consumption, the incentive is a program cost.

- Administrator and Participant Contribution: These can include technologies or equipment provided to customers for reporting usage information, two-way

[110] There are costs associated with implementation for price-based DR options that involve a change in rates, including administrative, data collection and assessment costs.
[111] The CPUC only allows the incremental costs of the program in the cost-effectiveness tests. For example, only the costs such as upgrading the billing system to handle the DR billing is permitted, rather than the whole cost of the billing system, which may serve other programs.

communications, enable the utility to control load from off-site, or perform some other function. These costs may also include any other equipment-related costs associated with demand response enabling technologies installed by the participant.

- Participant Transaction Costs: These include the opportunity costs associated with equipment installation, user education, program application, energy audits, developing and managing a load shed plan, and other opportunity costs to the participant.

- Value of Lost Service: This category includes any losses in productivity that occur because of demand reductions, such as reduced production during a demand response event due to equipment shutdown.[112]

- Increased Energy Consumption: These include costs incurred by the utility in providing additional electricity to customers as the result of a demand response program. For example, a demand response program that shifts load from peak to off-peak hours may result in a net increase in the total consumption of energy.

- Environmental Compliance Costs: Implementation of some DR programs may increase the costs required to comply with current and future environmental regulations. For example, a load curtailment program might require a customer to operate a fossil-fired backup generator that produces pollutants such as SO2, NOX, and greenhouse gases such as CO2, and other emissions. The cost of complying with the environmental regulation for these emissions should be accounted for.

16.1.2 Quantification of Benefits for Price-Based and Incentive-Based Program

There are also many different types of benefits that must be accounted for when evaluating DR program cost-effectiveness, each of the benefits is discussed in more detail in the sections below (not all programs will result in all of the benefits listed):

- Avoided Capacity: This is one of the primary and significant benefits for implementing demand response programs, the deferment or postponement of the need for new generation capacity, or otherwise reduce the cost of peaking generation capacity. Generally, avoided capacity costs for demand response programs can be very difficult to determine with a great degree of certainty, as the capacity avoided depends upon the specific characteristics of the demand response resources.[113]

- Avoided Energy: DR programs result in load curtailments in which customers forgo consumption for short time periods, avoiding energy costs. DR can also reduce energy

[112] If the production is shifted to another time period, the value of lost service should be based only on net productivity losses plus any costs associated with shifting work from one time period to another.
[113] Avoided capacity costs can best be estimated through the preparation of two long-term, optimized electricity scenarios, one without demand response programs and one with, and then compare the difference in present value revenue requirements between the two scenarios.

costs by shifting demand from high-priced hours to lower-priced hours. Avoided energy costs should be based on hourly energy generation or purchase costs, because energy costs and prices can vary significantly throughout the day and throughout the year.

- Avoided Transmission and Distribution Investments: DR programs can defer or reduce utility T&D capacity investments in local areas that are particularly stressed or in regions that are experiencing significant load growth. T&D capacity value should be considered separately from avoided capacity and energy costs. This helps to reflect the potential for demand response to target specific T&D.[114]

- Avoided Ancillary Service: DR programs may be able to provide the operating reserves necessary for the system to respond quickly to transmission or generator failures, to assist in responding to short-term and mid-term fluctuations in generation, and to ensure grid reliability.

- Avoided Environmental Compliance Costs: Some DR programs may be able to reduce the costs required to comply with current and future environmental regulations from reduced energy consumption, lowering the cost of complying with such regulations.

- Other Benefits: there may be other benefits that are not as well defined, analyzed, quantified, or accepted as the above. ERAV may want to consider these additional benefits in assessing the cost-effectiveness of demand response programs.

16.1.3 Cost-Benefit Analysis Framework

The CPUC has identified five different cost-effectiveness tests that can be used to analyze demand-side costs and benefits from different perspectives. These are briefly described below:

- Total Resource Cost (TRC): This test includes the costs and benefits experienced by all utility customers, including both program participants and non-participants.

- Participant Cost: This test includes the costs and benefits experienced by the customer who participates in the demand-side program.

- Ratepayer Impact Measure (RIM): The results of this test provide an indication of the impact of the program on those customers that do not participate in the programs, because if those customers' rates increase their bills will also increase.

- Program Administrator Cost (PAC): This test includes the energy costs and benefits that are experienced by the demand-side program administrator.

[114] In California, the avoided T&D costs can be further modified by a Distribution Factor that accounts for various factors that could limit avoided T&D costs.

- Societal Cost: This test includes the costs and benefits experienced by all members of society. The costs and benefits are the same as for the TRC test, except that they also include externalities, such as costs associated with environmental impacts and reduced costs for government services.

While all of the above cost-effectiveness tests should be considered in the evaluation of utility-funded (or self-funded programs) in order to obtain the most complete picture of the impacts on different parties, most programs rely upon one or two tests as the primary standard for analyses of program cost effectiveness. This is due to the challenges of working with multiple tests that provide different results, from different perspectives.

Of the above tests, the TRC framework is the most comprehensive standard for evaluating the cost- effectiveness of demand-side resources used by most utilities and regulators of DR programs. It includes all of the impacts to the program administrator and its customers, taking into consideration cost and benefit factors that are important for the planning energy efficiency programs such as other fuel savings, for example. For these reasons, the TRC framework is the most suitable for application to the situation in Viet Nam and is summarized in the below tables.[115]

Table 5: Benefits and Costs Used in the TRC Framework

Benefits and Costs Included in the TRC Framework (Quantified and Monetized)	
Benefits	**Costs**
• Avoided Capacity • Avoided Energy and additional resource savings (gas, water, etc.) • Avoided Transmission and Distribution Investments. • Avoided Environmental Compliance Costs • Monetary value of environment and other non-energy benefits • Other benefits, including Tax or other regulatory compensation	• Program Administration. • Program Administration Capital Costs • Financial Incentives to Participants • Administrator and Participant Contributions • Participant Transaction Costs

The TRC framework's advantage is its flexibility, and it can be used to evaluate energy efficiency, demand response, and fuel substitution programs. Due to its scope, the TRC framework includes total costs (participant and program) and can therefore capture the total

[115] The results of any of the above cost-effectiveness tests can be expressed as a ratio of total benefits to total costs. An program is said to "pass" the test if the benefit-cost ratio is greater than one (or if the net benefits are greater than zero). It is also recommended that both the benefit-cost ratio and the net benefits be reported when assessing demand-side resource cost-effectiveness. The net benefits can be expressed as the sum of all benefits minus the sum of all costs.

resource acquisition benefits. In addition, because the TRC includes participant costs, it provides an assessment of the DR program from a broad perspective.

The TRC limitations include the fact that it does not address revenue loss to the utility and other issues associated with just the power supplier because it includes participant costs. Different jurisdictions have made modifications to the TRC framework, and ERAV can choose to do so as it develops more familiarity with its specific programs.

Generally, when using the TRC framework, the program costs and benefits, which occur over the duration of the program or of the measure life, are discounted and compared on the basis of the present values. The results are expressed as:

- The present value of **net program benefits**: which is the total present value of program benefits minus the total present value of program costs; or as
- A **ratio of total present values of benefits and costs**: which is the total present value of program benefits divided by the total present value of program costs (sometimes referred to as the TRC results – see below table).

A net program benefits greater than 0 – where there is a positive net present value of benefits after costs, or a benefit to cost ratio greater than 1.0 – where the net present value of all program benefits is greater than the net present value of all program costs, means the measure/program will have a positive impact on the utility's resource acquisitions. Conversely, a negative net benefit or a TRC ratio of less than 1.0 means that the measure/program will negatively impact the utility's resource acquisition and will have the effect of increasing the cost of resource acquisition to the utility.

Table 6: Cost Benefit Expressions and Formulae

Expression	Description	General Formula
Program Benefits	Net Program Benefit (over the life of the program)	NPV ∑ benefits (VND) – NPV ∑ costs (VND)
Program Benefit-Cost Ratio	Ratio of Total Program Benefits to Total Program Costs (over the life of the program)	NPV ∑ benefits (VND) / NPV ∑ costs (VND)

Note: NPV = Net present value, where the series of cash flows over the program period are discounted and compared on the basis of present value to account for the time value of money.

Most DR programs options listed above (price-based or incentive-based) tend to have a TRC ratio between 1.0 and 2.0, while energy efficiency programs can have a TRC ratio of 2.0 or more. Exemplary programs have delivered TRC results in the range between 3.0 and 4.0 or higher.[116] It should be noted that measures and programs that have a TRC ratio less than 1.0

[116] "The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs", by M. Molina. Report Number U1402. American Council for an Energy-Efficient Economy, Washington, DC 20045

are sometimes adopted because they have value for other reasons or are required to address equity issues for energy efficiency. Some residential and low-income programs are examples of programs that may not pass the TRC but are still implemented. Utilities also aggregate the TRC ratios of the programs in their portfolio to present an overall ratio of the portfolio rather than of individual programs. Below is an example provided to regulators in the US State of Illinois by one of the utilities for the program portfolio in the state showing the range of benefit-cost ratios:

Table 7: Cost-Benefit Calculation for Utility Program Portfolio Example

Program	Benefits				Costs				IL Total Resource Cost (TRC) Test			
	Avoided Energy Production	Avoided Water Use	Other Benefits	Definition of Other Benefits	Non-Incentive Costs	Incentive Costs	Incremental Costs (Gross)	Incremental Costs (Net)	IL TRC Benefits	IL TRC Costs	IL TRC Test Net Benefits	IL TRC Test
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j) = (b+c+d)	(k) = (f+I)	(l) = (j-k)	(m) = (j/k)
Multi-Family Retrofit	$ 43,029,312	$ 8,787,330	$ 5,722,642	Avoided GHGs	$ 3,897,734	$ 11,934,204	$ 12,146,437	$ 11,398,744	$ 57,539,284	$ 15,296,479	$ 42,242,806	3.76
Heating & Appliance Incentive	$ 78,494,998	$ 17,420,895	$ 6,063,414	Avoided GHGs	$ 9,677,971	$ 19,152,664	$ 75,675,781	$ 56,159,534	$ 101,979,306	$ 65,837,505	$ 36,141,801	1.55
Single Family Retrofit	$ 6,174,820	$ 470,733	$ 705,938	Avoided GHGs	$ 2,746,293	$ 3,481,777	$ 4,387,154	$ 3,766,105	$ 7,351,490	$ 6,512,398	$ 839,093	1.13
Elementary Energy Education	$ 3,876,116	$ 3,760,923	$ 739,670	Avoided GHGs	$ 329,330	$ 1,787,683	$ 1,787,423	$ 1,412,064	$ 8,376,709	$ 1,741,394	$ 6,635,315	4.81
Behavioral Energy Savings	$ 3,180,524	$ -	$ 628,349	Avoided GHGs	$ 468,217	$ 2,783,495	$ 2,958,654	$ 2,810,721	$ 3,808,873	$ 3,278,938	$ 529,935	1.16
Residential New Construction	$ 3,644,191	$ -	$ 664,049	Avoided GHGs	$ 904,038	$ 1,240,200	$ 2,469,315	$ 1,975,452	$ 4,308,240	$ 2,879,490	$ 1,428,750	1.50
Economic Redevelopment	$ 1,095,673	$ -	$ 204,431	Avoided GHGs	$ 344,202	$ 679,576	$ 889,600	$ 622,820	$ 1,300,103	$ 967,023	$ 333,081	1.34
Retro-Commissioning	$ 5,550,183	$ -	$ 1,066,120	Avoided GHGs	$ 1,172,107	$ 1,040,788	$ 1,205,218	$ 1,227,846	$ 6,616,304	$ 2,399,953	$ 4,216,351	2.76
Custom Business	$ 74,920,919	$ -	$ 13,808,043	Avoided GHGs	$ 5,740,561	$ 11,474,852	$ 36,335,857	$ 25,751,493	$ 88,728,962	$ 31,492,054	$ 57,236,908	2.82
Business New Construction	$ 3,073,182	$ -	$ 561,898	Avoided GHGs	$ 313,105	$ 607,593	$ 1,814,018	$ 936,477	$ 3,635,080	$ 1,249,583	$ 2,385,497	2.91
Small Business Direct Install	$ 23,944,815	$ 1,286,610	$ 3,538,622	Avoided GHGs	$ 2,111,929	$ 4,206,116	$ 2,739,163	$ 2,739,163	$ 28,770,048	$ 4,851,093	$ 23,918,955	5.93
Business Incentive	$ 56,804,044	$ 497,368	$ 10,074,591	Avoided GHGs	$ 4,980,703	$ 3,436,445	$ 9,788,373	$ 7,874,250	$ 67,376,003	$ 12,854,953	$ 54,521,050	5.24
Sum of programs	$ 303,788,777	$ 32,223,859	$ 43,777,767		$ 32,686,191	$ 61,825,393	$ 152,196,994	$ 116,674,672	$ 379,790,403	$ 149,360,862	$ 230,429,541	2.54
Portfolio Costs					$ 30,340,200					$ 30,340,200	$ (30,340,200)	
Aggregate Portfolio	$ 303,788,777	$ 32,223,859	$ 43,777,767		$ 63,026,391	$ 61,825,393	$ 152,196,994	$ 116,674,672	$ 379,790,403	$ 179,701,062	$ 200,089,341	2.11

Source: Navigant, 2016.

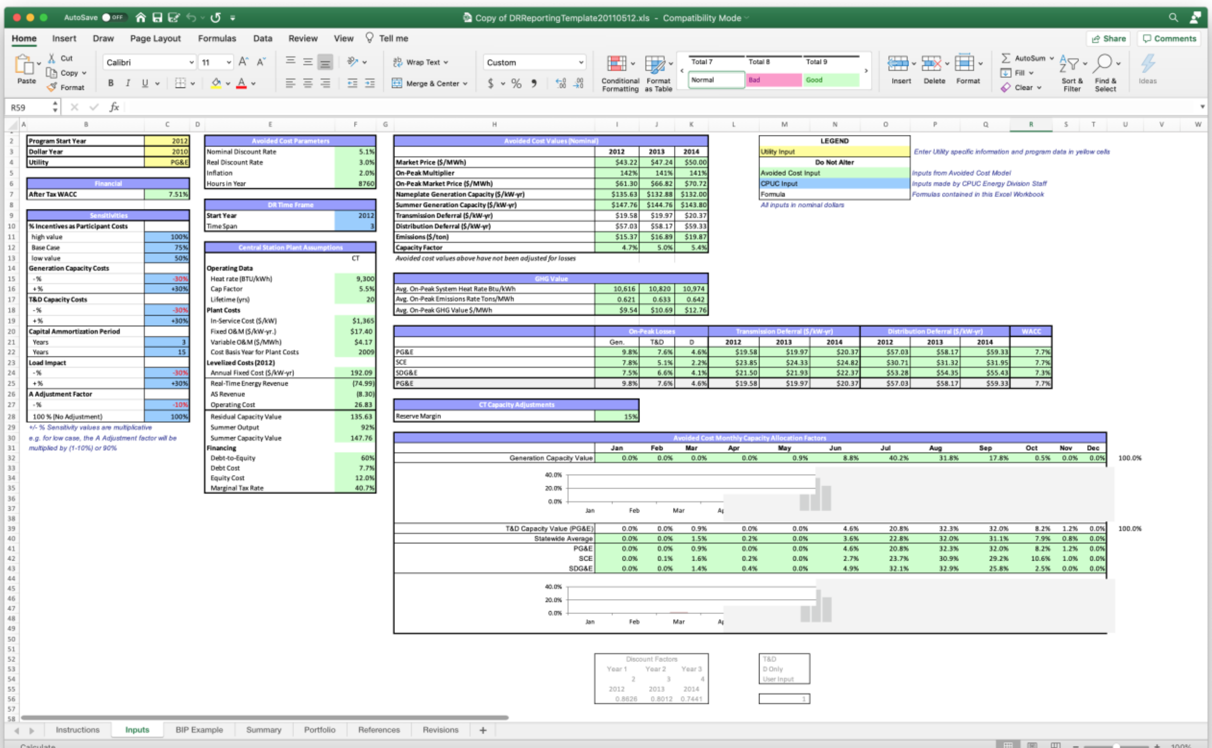
It should be noted that the CPUC's manual provides in-depth guidance on the determination of each of the cost and benefit categories. The manual is also available with a spreadsheet tool (available from the CPUC website: https://www.cpuc.ca.gov/General.aspx?id=7023) that has been specifically developed for the utility, and is pre-loaded with the factors listed below. The tool is available for use at no cost, however, it will need to be adapted with conditions and factors that are more reflective of Viet Nam's situations before it can be fully utilized.

1. Avoided Generation Capacity Cost (for further reference, the CPUC has also prepared a manual and tool for utilities that ERAV can consult to develop its own costs)[117]

[117] The "Avoided Cost Calculator" is an Excel-based spreadsheet model for use in demand-side cost-effectiveness proceedings at the California Public Utilities Commission (CPUC). Specifically, the model produces an hourly set of values over a 30-year time horizon that represent costs that the utility would avoid if demand-side resources produce energy in those hours. These avoided costs are the benefits that are used in determining the cost-effectiveness of these resources. It is available at: ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/2020%20ACC%20Electric%20Model%20v1c.xlsb

2. Avoided Energy Costs[118]
3. Avoided Transmission and Distribution Costs (values included in the spreadsheet are specifically for California's utilities, EVN will need to determine its own costs for T&D as well as any expansion costs)
4. Avoided Environmental Costs for Greenhouse Gases (GHG – this will require EVN-specific GHG emission factors)
5. Line Losses
6. Weighted Average Cost of Capital (WACC)

Figure 8: Screenshot from CPUC's TRC spreadsheet (Program data)



As outlined by the CPUC's manual, in order to carry out the assessment, the utility will need to specify the below quantitative information pertinent to each program to be evaluated. In the case of California, the utilities are responsible for determining their costs, either by the utility program manager or a third party hired to implement the program. This information is submitted to the Commission for verification as a part of utilities' reporting process. As recommended, for ERAV to fully utilize the tool, it will have to develop the required quantitative information, which are specific to EVN's service territories and the program or programs to be evaluated.

The information that will be required for meaningful TRC calculations include cost details specific to ERAV's DR program options, such as the estimated or determined load impacts

[118] For further reference: https://www.ethree.com/tools/acm-avoided-cost-model/

from the DR program or measure, the costs for ERAV to implement the DR program (for example, the administrative costs of the DR program or programs, EVN's cost of capital, and others programmatic costs such as incentive payments to participants, and any impacts to EVN's revenue from reduced sales). ERAV or EVN will also need to work with their customers participating in the DR program to estimate or project the participant costs (for example, from lost production due to electrical demand reduction, or other economic impacts such as overtime payments to workers due to shift in production hours, etc.). The following cost information are needed as input to the tool.

1. Load Impacts, in MW (the changes to the existing load profile, based on EVN's data and baselines for the particular region and time period)
2. Expected call hours of the program (periods of operation of EVN's program or programs, which will be used to determine energy savings)
3. Administrative Costs (total costs over program lifetime, discounted)
4. Participant Costs (for only those programs which are not using a percentage of incentives as a proxy measurement)
5. Capital Costs and Amortization Period, both to the utility and to the participant (for each investment)
6. Revenues from participation in CAISO Markets (not yet applicable for Viet Nam)
7. Bill reductions and increases (estimated or actual from EVN programs and baseline data)
8. Incentives paid (includes both availability and energy payments)
9. Increased supply costs (to EVN from fuel purchases)
10. Revenue gain/loss from changes in sales (usually assumed to be the same as bill reductions and increases)
11. Adjustment Factors (as applicable, if not required then EVN can determine default values based on its generation and costs data)

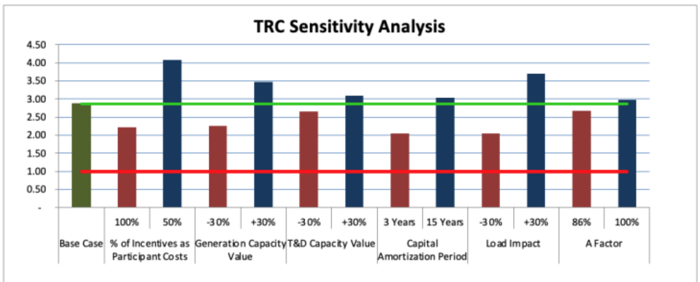
Figure 9: Screenshot from CPUC's TRC spreadsheet (example calculations)

Program Name

BIP Example

Base Case Results					
2010 Dollars	**Benefits**	**Costs**	**Net Benefits**	**Net $/kW-Yr.**	**Ratio**
TRC	$136,763,211	$47,697,120	$89,066,091	$158	2.87
PAC		$61,437,212	$75,325,999	$134	2.23
RIM		$61,839,968	$74,923,243	$133	2.21
PCT	$56,571,392	$42,428,544	$14,142,848	$25	1.33

Sensitivities	% of Customer Incentives in TRC		Generation Capacity Value		T&D Capacity Value		Capital Amortization Period		Load Impact		A Adjustment Factor	
	100%	50%	-30%	+30%	-30%	+30%	3 Years	15 Years	-30%	+30%	86%	100%
TRC	2.21	4.08	2.26	3.48	2.65	3.09	2.05	3.03	2.04	3.70	2.66	2.97
PAC	-		1.75	2.70	2.06	2.40	1.99	2.26	1.58	2.87	2.07	2.31
RIM	-		1.74	2.68	2.04	2.38	1.98	2.25	1.57	2.85	2.05	2.29



TOTAL	**2012**	**2013**	**2014**	**2010 NPV**			
TRC Costs	$ 17,976,547	$ 20,831,677	$ 20,832,545	$ 47,697,120			
PAC Costs	23,684,573	26,537,589	26,537,589	61,437,212			
RIM Costs	23,849,675	26,705,510	26,706,667	61,839,968			
PCT Costs	17,619,384	17,621,498	17,622,366	42,428,544			
Generation Capacity Value	$ 39,413,514	$ 40,868,591	$ 40,595,725	$ 96,946,782	T&D Values		
T&D Capacity Value	13,705,176	14,679,606	14,973,198	34,724,033	$ 57.03	$ 58.17	$ 59.33
Energy Value	46,103	100,514	106,374	199,447			
GHG Value	7,178	16,083	19,189	33,355			
Optional Benefits	2,000,000	2,000,000	2,000,000	4,815,677			
CAISO Market Value	16,875	15,750	22,500	43,916			
Total Benefits	**$ 55,188,846**	**$ 57,680,545**	**$ 57,716,987**	**$ 136,763,211**			
Participant Benefits	$ 23,492,512	$ 23,495,331	$ 23,496,487	$ 56,571,392			

NPV MW Impact (for levelized $/kW-Yr. calculation)	563

Sensitivities		2012	2013	2014	2010 NPV
% Incentives as Participant Costs					
100% of Incentive Costs	TRC Cost	$23,849,675	$26,705,510	$26,706,667	$61,839,968
50% of Incentive Costs	TRC Cost	$12,103,419	$14,957,845	$14,958,423	$33,554,272
Generation Capacity Costs					
Base Case -30%	TRC Benefits	$43,364,792	$45,419,967	$45,538,269	$107,679,176
Base Case +30%	TRC Benefits	$67,012,901	$69,941,122	$69,895,704	$165,847,245
T&D Capacity Costs					
Base Case -30%	TRC Benefits	$51,077,294	$53,276,663	$53,225,027	$126,346,001
Base Case +30%	TRC Benefits	$59,300,399	$62,084,426	$62,208,946	$147,180,421
Capital Ammortization Period					
3 Years	TRC Cost	17,976,547	33,211,625	33,212,492	$66,827,064
	PAC Cost	23,684,573	31,180,069	31,180,069	$68,610,941
	RIM Cost	23,849,675	31,347,990	31,349,147	$69,013,697
15 Years	TRC Cost	17,976,547	19,156,220	19,157,087	45,108,142
	PAC Cost	23,684,573	25,909,292	25,909,292	$60,466,345
	RIM Cost	23,849,675	26,077,213	26,078,370	$60,869,101
Load Impact					
Base Case -30%	TRC Benefits				$97,192,126
Base Case +30%	TRC Benefits				$176,334,296
Adjustment Factors					
A Factor at 86%	Gen. Cap. Value	$187.95	$157.79	$156.74	
	TRC Benefits	$51,247,495	$53,593,685	$53,657,414	$127,068,533
A Factor at 100%	Gen. Cap. Value	$219.82	$184.55	$183.32	
	TRC Benefits	$57,263,242	$59,831,523	$59,853,604	$141,865,673

16.1.4 Sensitivity Analysis of Key Factors

Because many of the costs and benefits of DR programs are based on uncertain inputs, with considerable variation among participants, these variations can make the costs and benefits challenging to verify. Some costs and benefits can be presented as precise quantities but are actually estimates due to the fact that they are based on assumptions and/or estimations. Those costs and benefits which cannot be easily quantified are often approximated or ignored in some cost effectiveness analyses. This approach can obscure the true costs and benefits of these programs and reduces the certainty in the analysis. Because of this, it is suggested that a sensitivity analysis should be conducted for a number of key variables. Where appropriate, sensitivity analysis should be conducted on these key factors:

1. Participant Costs
2. Avoided Capacity Cost
3. T&D Capacity Costs
4. Capital Amortization Period
5. Load Impact
6. Any Factor Adjustments to the Avoided Generation Capacity Cost

16.1.5 Numerical Example

The numerical example presented below is based on a Load Control program implemented in the US Pacific Northwest with the following parameters:

a. Description: This program covers customers with a standard-sized electric device (for example water heaters). A control switch is installed in each participant's location near the circuit breaker, which can be used to turn the electric device on or off once a message is received. Curtailments are initiated seasonally during peak hours of weekday mornings or afternoons as needed (winter), and are expected to comprise of fifteen events at a maximum of four hours/event, for a maximum total of sixty hours each year. A small number of participants will also have interval meters installed in addition to the switch to help program administrators document and verify the achieved level of demand savings during program events. An assumed average event response rate of 95% is used.
b. Operational details: The DR program is expected to take place over a seven-year period with the goal of achieving 30,000 participants. Per unit savings is projected to be 1.0 kW during events, which will reduce the class peak demand by 1.6% when it reaches steady-state in program year 7. After year 7, the utility plans to add new participants to maintain aggregate peak demand savings. This will require the utility to enroll new participants to offset projected growth in peak demand (2.2% per year) and replace customers that move or drop out of the program. The utility expects that about 7% of the customers per year will be lost due to changes in electric service (5%) or removal from the program (2%).
c. Costs: The utility has a budget of USD $100,000 up-front to develop the program in year 1. The utility projects that customer acquisition costs are USD $25/customer for marketing and back-office costs. The switching costs USD $175/customer installed. Load impact verification costs are USD $5/customer. The utility will also offer

customers an incentive for participating in events (USD $6.66/month bill credit for three months = USD $20/customer-year). The notification system is expected to cost the utility USD $7/customer-year over the life of the program. Inspection costs is estimated at USD $10/customer-year for the inspection of a sample of switches/communication system and loggers and their maintenance. The administration cost to run the program every year is estimated to be USD $60,000/year. These costs are anticipated to grow by 2% per year.

d. Benefits: The utility projects that in year 1 the value of avoided cost of peak and off-peak energy is USD $ 0.075 per kWh and USD $ 0.045 per kWh. These costs are projected to increase at 2% per year. Environmental benefits are estimated to be USD $0.008 per kW-year, increasing 2% per year. The first year avoided cost of capacity is set at USD $80 per kW-year, and is expected to increase by 3% per year thereafter. T&D savings includes both line loss savings and reduced investment in generating plant. The utility has deemed that the average T&D cost savings associated with the program are USD $3 per kW-year, which increases at a rate of 3% per year. The utility also has a secondary voltage level loss factor of 6%, thus any associated reduction in sales and peak demand means 106% of that electricity need not be generated and maintained for reserves, respectively. Avoided capacity benefits account for ~95% of total benefits. No reliability benefits are calculated because this resource is directly integrated into the utility's planning process.

e. Results: Using these inputs and assuming the program life is 20 years, the utility anticipates total program costs, on a present value basis using a discount rate of 8.8%, to be USD $19.63 million, with program benefits to be USD $25.12 million. Therefore, this DR program produces USD $5.49 million in net benefits with a TRC benefit-cost ratio of 1.28.

Table 8: DR Program cost benefit analysis numerical example

Year Index	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Year																				
Utility System Characteristics																				
Forecasted Retail Sales (GWh)	23,000	23,460	23,929	24,408	24,896	25,394	25,902	26,420	26,948	27,487	28,037	28,598	29,170	29,753	30,348	30,955	31,574	32,206	32,850	33,507
Forecasted Peak Demand (MW)	4,000	4,088	4,178	4,270	4,364	4,460	4,558	4,658	4,761	4,865	4,972	5,082	5,194	5,308	5,425	5,544	5,666	5,791	5,918	6,048
Residential Retail Sales (GWh)	8,740	8,915	9,093	9,275	9,460	9,650	9,843	10,040	10,240	10,445	10,654	10,867	11,084	11,306	11,532	11,763	11,998	12,238	12,483	12,733
Residential Peak Demand (MW)	1,520	1,553	1,588	1,623	1,658	1,695	1,732	1,770	1,809	1,849	1,890	1,931	1,974	2,017	2,061	2,107	2,153	2,200	2,249	2,298
DR Program Characteristics																				
Number of New Participants (Units)	4,286	4,586	4,886	5,186	5,486	5,786	6,086	2,760	2,821	2,883	2,946	3,011	3,077	3,145	3,214	3,285	3,357	3,431	3,506	3,584
Number of Returning Participants (Units)	0	3,986	7,971	11,957	15,943	19,929	23,914	27,900	28,514	29,141	29,782	30,437	31,107	31,791	32,491	33,206	33,936	34,683	35,446	36,226
Number of Total Participants (Units)	4,286	8,571	12,857	17,143	21,429	25,714	30,000	30,660	31,335	32,024	32,728	33,448	34,184	34,936	35,705	36,490	37,293	38,114	38,952	39,809
Peak Period Energy Reduction (MWh)	244	489	733	977	1221	1466	1710	1748	1786	1825	1866	1907	1949	1991	2035	2080	2126	2172	2220	2269
Off-Peak Period Energy Increase (MWh)	244	489	733	977	1221	1466	1710	1748	1786	1825	1866	1907	1949	1991	2035	2080	2126	2172	2220	2269
Proportion of Class Retail Sales (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity Reduction (MW)	4.07	8.14	12.21	16.29	20.36	24.43	28.50	29.13	29.77	30.42	31.09	31.78	32.48	33.19	33.92	34.67	35.43	36.21	37.00	37.82
Proportion of Class Peak Demand (%)	0.3%	0.5%	0.8%	1.0%	1.2%	1.4%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
Benefits																				
Avoided Energy Cost Savings ($MM)	$0.01	$0.02	$0.02	$0.03	$0.04	$0.05	$0.06	$0.06	$0.07	$0.07	$0.07	$0.08	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10	$0.10	$0.11
Avoided Capacity Cost Savings ($MM)	$0.35	$0.71	$1.10	$1.51	$1.94	$2.40	$2.89	$3.04	$3.20	$3.37	$3.54	$3.73	$3.93	$4.13	$4.35	$4.58	$4.82	$5.07	$5.34	$5.62
Avoided T&D System Cost Savings ($MM)	$0.01	$0.03	$0.04	$0.05	$0.07	$0.08	$0.10	$0.11	$0.11	$0.12	$0.13	$0.13	$0.14	$0.15	$0.15	$0.16	$0.17	$0.18	$0.19	$0.20
Environmental Benefits ($MM)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Reliability Benefits ($MM)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total ($MM)	***$0.37***	***$0.75***	***$1.16***	***$1.60***	***$2.05***	***$2.54***	***$3.05***	***$3.21***	***$3.38***	***$3.55***	***$3.74***	***$3.94***	***$4.14***	***$4.36***	***$4.59***	***$4.83***	***$5.08***	***$5.35***	***$5.63***	***$5.93***
Benefits - Present Value ($MM)	**$25.12**																			
Costs																				
Program Development Costs ($MM)	$0.10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Customer Acquisition Costs ($MM)	$0.88	$0.96	$1.04	$1.13	$1.22	$1.31	$1.40	$0.65	$0.68	$0.71	$0.74	$0.77	$0.80	$0.83	$0.87	$0.91	$0.94	$0.98	$1.03	$1.07
Annual Program Administration Costs ($MM)	$0.06	$0.06	$0.06	$0.06	$0.06	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.09	$0.09
Annual Program Variable costs ($MM)	$0.16	$0.32	$0.49	$0.67	$0.86	$1.05	$1.25	$1.30	$1.36	$1.42	$1.48	$1.54	$1.60	$1.67	$1.74	$1.82	$1.89	$1.97	$2.06	$2.15
Total ($MM)	***$1.20***	***$1.34***	***$1.60***	***$1.86***	***$2.14***	***$2.43***	***$2.72***	***$2.02***	***$2.11***	***$2.19***	***$2.29***	***$2.38***	***$2.48***	***$2.58***	***$2.69***	***$2.80***	***$2.92***	***$3.04***	***$3.17***	***$3.30***
Costs - Present Value ($MM)	**$19.63**																			
Net Benefits ($MM)	***5.49***																			
Benefit Cost Ratio	***1.28***																			

Source : Northwest Power Planning Council, 2016.

Chapter

17

THE PATH TO DR DEPLOYMENT IN VIETNAM

17 The path to DR deployment in Vietnam

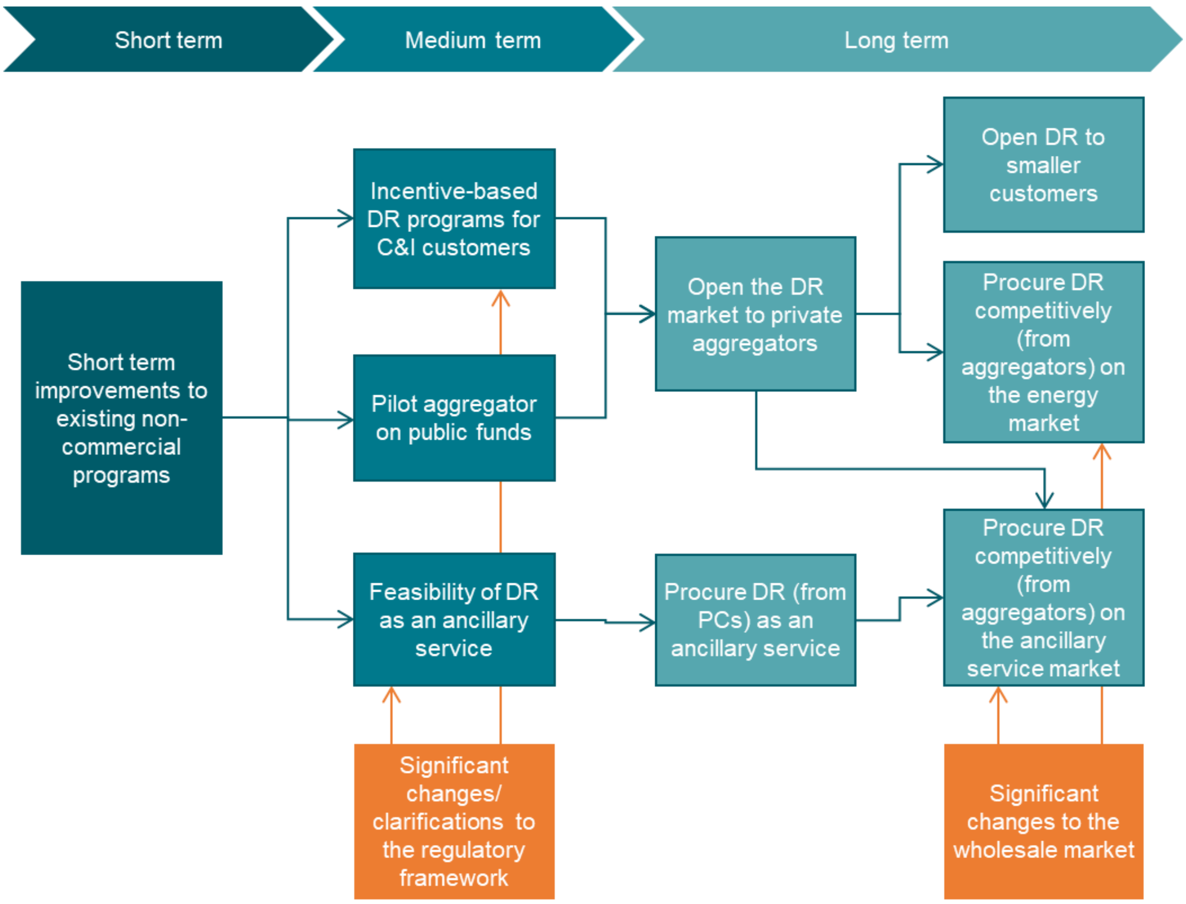
This chapter articulates the recommendations from Chapters 12 to 15 and describes a global path to DR development in Vietnam in the short, medium and long term. Short term recommendations are further developed and a short term action plan is defined.

17.1 Overview

The recommendations from previous chapters lay out several longt-term options for the deployment of DR in Vietnam. At this stage, there is not enough evidence to determine which option(s) is the best in the long term. All options could be implemented in parallel ; or they could be staged through time, one after the other ; or it will become clear, at some point, that one of them is sufficient to achieve Vietnam's load reduction targets.

The two charts below provide an overview of the options that we have explored in Chapters 12 to 15, starting with **Incentive-based DR (CLP and EDRP - Program 1 from Circular 23)**. For this program, in the short term, several improvements must be brought to the existing non-commercial DR programs. In subsequent stages, three options can be envisaged: switch from non-commercial to commercial DR programs within the existing PC-administered framework ; prepare the terrain for the aggregator model, by running a pilot aggregator program on public funds ; and examine the feasibility of on-selling DR as an ancillary service to the system operator. Significant changes or clarifications need to be brought to the regulatory framework to make this possible.

The path to DR deployment: Incentive-based DR (CLP and EDRP - Program 1 from Circular 23)

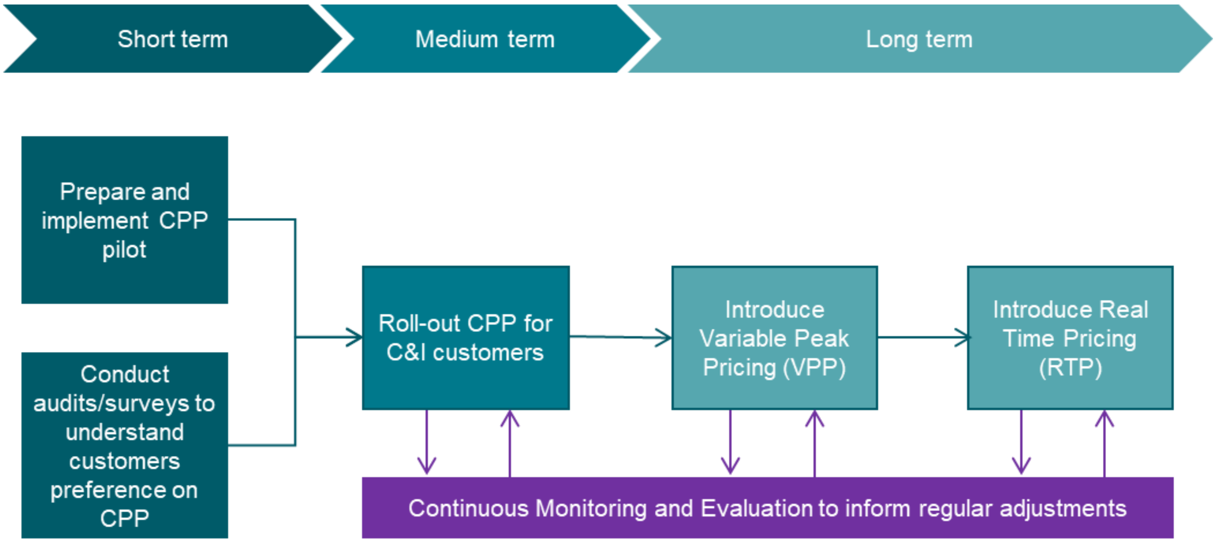


In the long term, assuming that the development of the VWEM continues in parallel, this would pave the way for private aggregators trading DR on either the energy market, or on a (yet to be created) competitive capacity or ancillary service market. As aggregators get up to speed, they could also start targeting smaller customers. It is too early at this stage to recommend one long-term option over the others. We suggest that the Vietnamese authorities keep all these options on the table until enough information becomes available to select one or several of them, and dismiss the others.

As regards the **peak load electricity tariff program (Sub-program 2.2 from Circular 23)**, the path is more straightforward. Regulatory obstacles are much less important: the possibility of introducing peak time tariff is already mentioned in PM Decision 28/2014/QD-TTg *Regulations on structure of electricity retail tariff*.

The first step towards the deployment of critical peak pricing (CPP) is to prepare and implement a pilot program. In parallel, it is strongly recommended to conduct audits and surveys to understand customers preference on CPP. These surveys could also bring valuable insights for all DR and DSM programs.

The path to DR deployment: "Sub-Program 2.2" from Circular 23 (peak load electricity tariff)



After the pilot, CPP could progressively be extended to a larger number of C&I customers. In the longer term, keeping pace with the evolution of the VWEM, variable peak pricing (VPP) and ultimately real-time peak pricing (RTP) could be introduced.

In addition to the necessary adjustments to the regulatory framework, a range of cross-cutting measures are required to support the deployment of these various options:

- Continuous monitoring and periodic assessment of technological readiness
- Preparation of the switch from manual / local DR to automated / remotely controlled DR (Direct Load Control program)
- Building the capacity of EVN and PCs to implement DR
- Empower energy managers for commercial and industrial facilities with demand response training

17.2 Short term action plan

The following section defines a 8-point Action Plan for the short term.

Short term action plan: overview

N°	Title	Pertains to	Lead
1	Continue efforts to encourage behavior change in C&I customers	Non-commercial DR (Program 1)	PCs
2	Build the capacity of PCs, EVN, and C&I customers	Non-commercial DR (Program 1)	MOIT
3	Adopt a regional approach to triggering DR events	Non-commercial DR (Program 1)	EVN
4	Conduct Monitoring and Evaluation (M&E) of existing programs, including Cost-Benefit Analysis (CBA)	Non-commercial DR (Program 1)	MOIT
5	Conduct studies/surveys to understand customers preferences	Cross-cutting	MOIT
6	Design a pilot Critical Peak Pricing program	Peak load electricity tariff program (Sub-program 2.2)	MOIT
7	Assess the technological readiness for DR	Cross-cutting	MOIT
8	Clarify the regulatory framework for commercial DR	Commercial DR (Program 1)	MOIT

The tables below provide a detailed description of each action, with a reference to the recommendations in the previous chapters. A lead organization is proposed for each action (TO BE VALIDATED WITH GIZ AND ERAV)

Action n°1. Continue efforts to encourage behavior change in C&I customers
Addresses the following recommendations: Continue efforts to encourage behavior change (Chapter 12)
Action to be led by: **PCs** with support from: **MOIT, media/press, local governments**
Detailed description A campaign has already been conducted as a part of the country-wide roll-out of the DR program. However, according to stakeholders, PCs lack the means to sustain their efforts in awareness raising. **Low-cost "nudges"** could encourage behavior change, such as: - "Name and praise": PCs publish a list of customers that responded the best to DR events, thus providing positive exposure to the best performers - "Peer comparison": PCs provide C&I customers with information on how their own performance in DR programs compare to the average of their peers, thus encouraging customers to do better than the average The media should also be called upon to raise awareness about DR and promote behavior change in customers. PCs could invite **local media** to workshops about DR, so journalists become more familiar with the concepts and importance of DR. PCs could also prepare press kits containing useful material for journalists. PCs could also consider **providing special benefits** to participating customers. For instance, they could offers rebates to participating customers on specific services such as grounding test, power suply system commissioning/maintenance ...)

Action n°2. Build the capacity of PCs, EVN, and C&I customers

Addresses the following recommendations: Technical and financial support to C&I customers in becoming more flexible (Chapter 12) ; Ensure EVN and PCs have the necessary human resources to implement DR (Chapter 15) ; Ensure EVN and PCs can help C&I customers become active DR players (Chapter 15) ; Empower energy managers for commercial and industrial facilities with demand response training (Chapter 15)

Action to be led by: **MOIT** with support from: **GIZ, ADB (TBC)**

Detailed description

The further deployment of DR will require capacity building at several levels:

1) EVN and PCs' grid operation staff need to be trained to implement DR events. Expanded staffing in the area of demand response should be planned and mapped in accordance with the sophistication and wide-spread use of demand response.
2) PCs' customer relation staff need to be trained to interact with customers regarding DR programs. It is important that power utilities can support participating customers in understanding how they can participate in DR without hampering their operations. So, PC staff should be in sufficient number and trained to help C&I consumers with appropriate load management plans to achieve government mandated DR targets.
3) C&I customers need to increase their knowledge as regards load management and DR. At least, we recommend adding one or more modules specifically on demand response to formalize demand response training as part of Circular 39/2011/TT-BCT "Providing for training, grant of certificates of energy management and energy auditors". Below is a description of the recommended modules, to be added at the end of the existing 5-day course:

Recommended supplemental modules for DR		
13.	Introduction to Demand Response	1 day
14.	Integrating Available Demand Response Solutions into your Operations	1 day

4) Some C&I customers may also require support in designing, and investing in, load management solutions. Adopting DR requires that customers adapt their operations during peaks and/or invest in own generation or behind the meter storage. To do so, C&I customers need to understand their load profile and power needs, identify physical (eg own generation) and non-physical (eg. adjust their operations during peak time) investments that could lead to a better management of their load. That support could be through technical support, energy management, and possibly financing instruments. A specific source of funding would have to be mobilized: at this stage we see two possibilities, either through the Science and Technology Development Fund, or with support from donors (the ADB for instance is interested in the development of an Energy Efficiency fund).

It would only make sense to **tie DR capacity building with existing EE programs**. DR could relatively easily be integrated into EE trainings and audits ; load management technologies could be included among EE technologies eligible for financial support. EVN/PCs could include load management in EE audit/consultancy and then help customer obtain financing from existing EE funds.

Action n°3. Adopt a regional approach to triggering DR events

Addresses the following recommendations: Adopt a regional approach to triggering DR events (Chapter 12)

Action to be led by: **EVN** with support from: **PCs**

Detailed description

For 2020, EVN has provided an annual DR schedule with monthly events scheduled for the various regions with some small variabilities in peak times. Our understanding is that these events have been designed with a centralized view to support transmission congestion in the South. We recommend considering DR events also from a more decentralized stand, and possibly allowing PCs to schedule and trigger some DR events on a regional rather than national basis one. Adopting a regional approach to trigger DR events would increase the positive impact of DR relative to decongesting the local distribution systems.

The following activities will have to be conducted:

- At the PC level
  - ➢ Analysis of the load curve in each region
  - ➢ Identification of congestions on the local distribution networks
- At the national level
  - ➢ Identification of congestions on the transmission lines
  - ➢ Analysis on seasonality issues and their impact on the load, on the operating reserve and on the cost of electricity

Based on the above, PCs will be able to come up with their own criteria for triggering a DR event, and their own regional targets for load reduction during DR events. It is suggested to use the year 2019 as a basis to simulate, based on historical data, when DR events should have been triggered if regional criteria had been used. Once an agreement is reached between the PCs and EVN, the operating protocol for DR events will then be adjusted.

Action n°4. Conduct Monitoring and Evaluation (M&E) of existing programs, including Cost-Benefit Analysis (CBA)

Addresses the following recommendations: Conduct Monitoring and Evaluation of existing programs (Chapter 12) ; Set up a comprehensive framework for planning and monitoring of DR (Chapter 15)

Action to be led by: **MOIT** with support from: **PCs, EVN**

Detailed description

Monitoring and Evaluation (M&E) is required in order to understand the impact of existing programs, adjust them on a regular basis to make them more efficient, and to start building useful knowledge for the next stages of DR development in Vietnam.

We understand that each PC already keeps track of the implementation of DR events and collects data on participation and actual load reduction. It is recommended to create an overarching, systematic Monitoring and Evaluation framework for these programs. The M&E framework would define indicators and fix targets against which actual results would be compared. The M&E data could be used to inform necessary adjustments to the program, and to advocate for the further development of DR in Vietnam.

In parallel, a Cost-Benefit Analysis must be conducted. The CBA will showcase the real benefits of DR in Vietnam. It will constitute a powerful tool for DR advocates, starting with ERAV, to continue lobbying for the expansion of DR programs. Of note, CBA is data-intensive (see Chapter 16). Thus, it is recommended to conduct it in coordination with the M&E activities as well as the customers surveys (Action n°5), so that the data can be shared between these activities, for better efficiency.

Action n°5. Conduct studies/surveys to understand customers preferences

Addresses the following recommendations: Conduct studies/surveys to understand customers preferences (Chapter 13)

Action to be led by: **MOIT** with support from: **GIZ, ADB (TBC)**

Detailed description

The success of DR is highly dependent on customers' behavior. Thus, it is important to anchor the design of DR programs on a precise understanding of the customers' load curves and consumption patterns and of their ability to adapt their consumption in response to price signals.

It is recommended to carry out a specific study of customers' preferences, comprising of the following:

- Analysis of existing data on load curves of various categories of customers. C&I customers should be disaggregated in smaller clusters based on their main line of business (eg. Steel, cement, agroprocessing, etc for Industrial ; hotels, shopping malls, office buildings, etc for Commercial)
- Survey of a representative sample of customers, with questions on their energy consumption patterns, on their flexibility to adjust their load, and on their appetite for various kinds of DR programs and on various levels of financial incentives
- Optional: Market survey of a sample of C&I customers (May be required if existing data is insufficient. Synergies may be found with the ongoing ADB mandate on DR potential assessment)

Synergies can probably be found with the ongoing ADB-funded study on DR potential. The result of the survey will directly inform the design of a CPP pilot (Action n°6)

Action n°6. Design a pilot Critical Peak Pricing program

Addresses the following recommendations: Adopt critical peak pricing (CPP) for the peak time tariff program (Chapter 13) ; Determine the program's key parameters (Chapter 13) ; Adopt a progressive approach to implementation (Chapter 13)

Action to be led by: **MOIT** with support from: **GIZ (TBC)**

Detailed description

Objective of the assignment: design a comprehensive CPP pilot, that would pave the way for a larger deployment of CPP in Vietnam.

Activity 1. Design of the pilot program

- Review the existing legal and regulatory framework for CPP, identify potential gaps in the regulation
- Define the objectives of the pilot in terms of number of customers, load reduction to be achieved, duration, etc
- Recommend implementation partners (particular attention to be paid to selection of the utility(ies) responsible for implementing the pilot – based on motivation, existing skills, willingness to share data etc)
- Determination of the key parameters of the pilot program: Peak to off-peak price (POPP) ratio, Peak duration, Peak period frequency, Number of pricing periods, Eligibility and enrolment. See Chapter 13 for indications based on international experience to help with the determination of these parameters
- Detailed recommendation regarding target customers
- Validation of the pilot design with ERAV

Activity 2. Preparation of the implementation plan

- Time-bound implementation plan
- Communication plan
- Capacity building measures, including in relation with the existing energy auditors training and certification program (see Action n°2)
- M&E framework ; M&E baseline and targets
- Validation of the implementation plan with ERAV

Action n°7. Assess the technological readiness for DR

Addresses the following recommendations: Continuous monitoring and periodic assessment of the technology (Chapter 15)

Action to be led by: **MOIT** with support from: **PCs, EVN**

Detailed description

The deployment of DR in other countries has been extensively based on smart metering and other automation technologies. In Vietnam, it will be important to carefully assess the current state of the technology, and to anticipate on technology evolutions. In particular:

- The technology used for the on-going smart meter roll-out program should be assessed for compatibility with various DR programs
- The technical norms and standards governing smart meters and smart grids should be reviewed to ensure that they are fully compatible with existing and future DR Programs
- In the future, the design of new smart meters and smart grid projects should be reviewed for compatibility with DR programs. If needed, adjustments will be made to the design prior to implementation to ensure full compatibility with existing and future DR programs
- The possibility of remotely controlling the customers' load during critical peak periods should be given specific attention

It is recommended to conduct an initial technology readiness assessment now. In the future, similar assessments will be conducted at regular intervals (eg every 3 years). Is is also recommended to formalize a permanent communication protocol for constructive dialogue between the entitites in charge of smart meter / smart grid deployment on the one hand, DR programs on the other.

Action n°8. Clarify the regulatory framework for commercial DR

Addresses the following recommendations: Necessary changes to the framework for commercial CLP and EDRP (Chapter 14)

Action to be led by: **MOIT** with support from: **legal/fiscal experts (to be potentially funded by international partners)** and in cooperation with**: MOF**

Detailed description

Within the existing framework, PCs are not entitled to recover the costs of CLP and EDRP in the tariff. This, in turn, directly impacts their ability to offer adequate financial incentives to customers participating in CLP and EDRP. Indeed, DR costs are not direct expenses related to the generation, transmission and distribution of electricity. Therefore, they are not explicitly eligible for cost recovery through tariff. This point has been the object of exchanges between ERAV/MOIT and MOF for several years. The most recent correspondence on this issue is formed of MOIT letter dated December 31, 31 (Letter 10192 /BCT-TKNL) and MOF response dated March 27, 2020 (Letter 3609/BTC-TCDN). In their answer, MOF recommend that MOIT takes its case to the Commission for the Management of State Capital and Enterprises (CMSC) to study and clarify the definition of what constitutes a direct expense.

The objective of Action n°8 is to provide MOIT with legal and fiscal expertise for the next stages of the process, until a resolution is found that allows the recovery of the costs of CLP, EDPR, and more generally any DR program that may be implemented in the future.

Chapter

18

NUMERICAL SIMULATIONS

18 Numerical Simulations

To provide ERAV with indicative numbers regarding the potential benefits of Demand Response and potentential design of financial mechansism, we have carried out three numerical simulations. These included a simulation of a simplified Cost Benefit Analysis of the 2015 DR pilot, simplified numerical simulations for the determination of CLP and EDRP financial mechanisms, and a simplified numerical simulation for the determination of a CPP tariff.

The purpose of these simulations is to present **possible results** which are to be used for **indicative purposes only**, and should not be taken as definitive. Singnificant assumptions have been made due to lack of data, and these would need to be verified and updated before the results can be taken as final. Though preliminary, our results can give an idea on the quantification of the benefits of DR programs and the potential design of financial mechanisms. Due to the indicative nature of our results, we have also run sensitivities on key assumptions to show the range in possible results.

Spreadsheets providing these simulations are provided in Appendix E of this report.

18.1 Simplified Cost Benefit Analysis of the 2015 Pilot

18.1.1 Program details

The 2015 DR pilot ran 4 events and achieved a 4.75% load reduction. Two of the events were CLP events, and the remaining 2 were EDRP events. The details of each event are provided in the table below.

Event	Time	No. customers participating	Average Capacity reduction	Rate of capacity reduction compared to customer's demand	Total supporting finance transferred to customer (VND)
1st CLP	14:00 – 16:00 7/10/2015	9	647 kW	5%	2307056
1st VEDRP	10:00 – 12:00 21/10/2015	10	653 kW	4%	10578765
2nd CLP	8:00 – 10:00 4/11/2015	12	752 kW	6%	3875120
2nd VEDRP	15:00 – 17:00 18/11/2015	11	461 kW	4%	3465392
Total			628,25 kW	4.75%	20,226,333

The program paid the following incentives per kWh of reduced demand:

- CLP (informed 24h in advance): applicable tariff per kWh
- EDRP (2h in advance): 3x tariff in Peak hours, 2x tariff in Standard hours

18.1.2 Simplified CBA Methodology

We have carried out a simplified CBA exercise to compare the costs and benefits of the 2015 Pilot. While there are many costs and benefits that can be examined, our simplified methodology focused on comparing the avoided energy (benefits) to the financial incentives paid out (costs).

Benefits and Costs Included in the TRC Framework (Quantified and Monetized)	
Benefits	**Costs**
• Avoided Capacity	• Program Administration
• **Avoided Energy:** • **Marginal cost of generation during peak** • **T&D losses**	• Program Administration Capital Costs
• Avoided T&D Investments	• **Financial Incentives to Participants**
• Avoided Environmental Compliance Costs	• Administrator and Participant Contributions
• Monetary value of environment and other non-energy benefits	• Participant Transaction Costs
• Other benefits including Tax or other regulatory compensation	

18.1.3 Assumptions

While we have program cost data through the total incentives paid for each event, we have made the following program benefits assumptions:

Avoided costs of energy	VND/kWh
Avoided generation costs	3,500
Avoided T&D losses	350
Total	3,850

Avoided generation costs are calculated based on the avoided marginal costs of the most expensive generating unit.. We have assumed avoided T&D losses to be 10% of avoided generation costs.

Our assumptions are in line with EVN's average avoided cost for 2019 for DR programs of 3,785 VND/kWh (cost savings due to not mobilizing DO oil-fired power plants).

18.1.4 Results and key findings

The below table presents the results of our simulations, highlighted through the total cost of the program, the total benefits of the program, and the benefit cost ratio.

	Cost: Incentive paid (VND)	Benefits: Avoided cost of energy (VND)	Benefit to Cost ratio
1. First CLP event (informed 24h in advance)	2,307,056	4,981,900	2.2
2. First VEDRP event (informed 2h in advance)	10,578,765	5,028,100	0.5
3. Second CLP event	3,875,120	5,790,400	1.5
4. Second VEDRP event	3,465,392	3,549,700	1.0
Total for 4 events	20,226,333	19,350,100	**1.0**

Based on the results, our key findings indicate that:

- The 2015 pilot had a benefit-to-cost ratio of 1.0. This is on the lower side, but still indicates a favorable outcome.
- The 1st EDRP event has a benefit-to-cost ratio well below 1.0. This indicates that the incentive paid during peak hours EDRP, of 3x the peak-hour TOU tariff, might be too high in comparison with the benefits.
- Detailed data on avoided costs is crucial for DR incentive calculation.

18.2 Simplified numerical simulation for the determination of CLP/EDRP financial incentives

We simulated a CLP and EDRP program for C&I customers in order to present possible results of what a direct incentive mechanism could look like. The programs are designed to include 2 compensation mechanisms: a fixed incentive (per kW committed) and a variable incentive (per kWh of energy actually reduced).

18.2.1 Principles of the program design

The financial incentives for CLP and EDRP are designed as a percentage of the expected cost saving benefit of the program, which are given to the customer. The logic behind this is that benefits should be shared among customers and utilities, as utilities would use their share of the benefits to recoup costs of program implementation. The expected cost saving are based on the avoided cost, which is equal to the marginal cost of the most expensive generation units on the grid.

18.2.2 Assumptions

We made the following assumptions on participating customers in the programme:

- **3,000 participating customers**: this is based on a reasonable increase from actual figures from 2019 non-commercial program (more than a thousand customers are enrolled in total)

- **Average customer peak demand of 2,000 kW**: this is based on actual figures from the 2015 pilot and the 2019 non-commercial program (the average individual load is in the 500-1500kW range)
- **Average load reduction achieved of 5% for CLP and 8% for EDRP**: this is based on actual figures from the 2015 pilot and the 2019 non-commercial program (the average load reduction for one event ranges from 4% to 13%)

The number and duration of events we assumed are presented below:

CLP	EDRP
3 events over 1 year	**7 events over 1 year**
Based on events organized by EVN in 2019 (3 planned events)	Based on events organized by EVN in 2019 (7 emergency events)
2 hours each	**2 hours each**
Based on duration of events in 1st and 2nd CLP events in 2015	Based on duration of events in 1st and 2nd EDRP events in 2015

We have assumed the following program cost assumptions for CLP and EDRP:

CLP

Incentive Paid	VND/kWh
Fixed Monthly Payment	0
Energy Payment	1,540*

*based on 40% of the avoided cost benefits being attributed to customers

Program Implementation Costs	VND
Monthly cost per customer	45,000
Incentive management	5% of total incentive
Fixed system cost	115 million

EDRP

Incentive Paid	VND/kWh
Fixed Monthly Payment	250*
Energy Payment	2,503**

*based on 5% of the benefits being attributed to customers
**based on 50% of the benefits being attributed to customers

Program Implementation Costs	VND
Monthly cost per customer	45,000
Incentive management	5% of total incentive
Fixed system cost	115 million

We have assumed the following cost savings (benefits) assumptions for CLP and EDRP:

CLP	
Avoided Costs	**VND/kWh**
Avoided generation costs	3,500
Avoided T&D losses	350

EDRP	
Avoided Costs	**VND/kWh**
Avoided generation costs	4,550
Avoided T&D losses	455

Avoided generation costs are calculated based on the avoided marginal costs of the most expensive generating unit. We have assumed that avoided generation costs are 30% for EDRP than for CLP, to reflect that the value of emergency DR is higher for the system than that of planned DR. We have assumed avoided T&D losses to be 10% of avoided generation costs. Our assumptions are in line with EVN's average avoided cost for 2019 for DR programs of 3,785 VND/kWh (cost savings due to not mobilizing DO oil-fired power plants).

18.2.3 Indicative Results and Key Findings

The indicative results of the programs are presented below, along with the results of a sensitivity analysis testing different assumptions. The programs shows a benefit-cost ratio greater than 1 for all scenarios, indicating that the incentive payments assumed in the program are sustainable.

	Base Case	50% increase in # of events	10pp increase load reduction
CLP	1.22	1.46	1.81
EDRP	1.54	1.65	1.66

Through running this numerical simulation, we have found that the benefit-to-cost ratio is particularly sensitive to the following factors:

- Number of events taking place (because some costs are fixed, the more events, the higher the benefits – within acceptable limits)
- Customer behaviour (amount reduced)
- Fixed costs

Moving forwards, the following is needed to move from study of possible financial incentives to implementation of a direct financial incentive program:

- Adjust assumptions based on actual numbers, as available
- Begin with an incentive that is on the lower side, that can be progressively increased based on results of first implementation

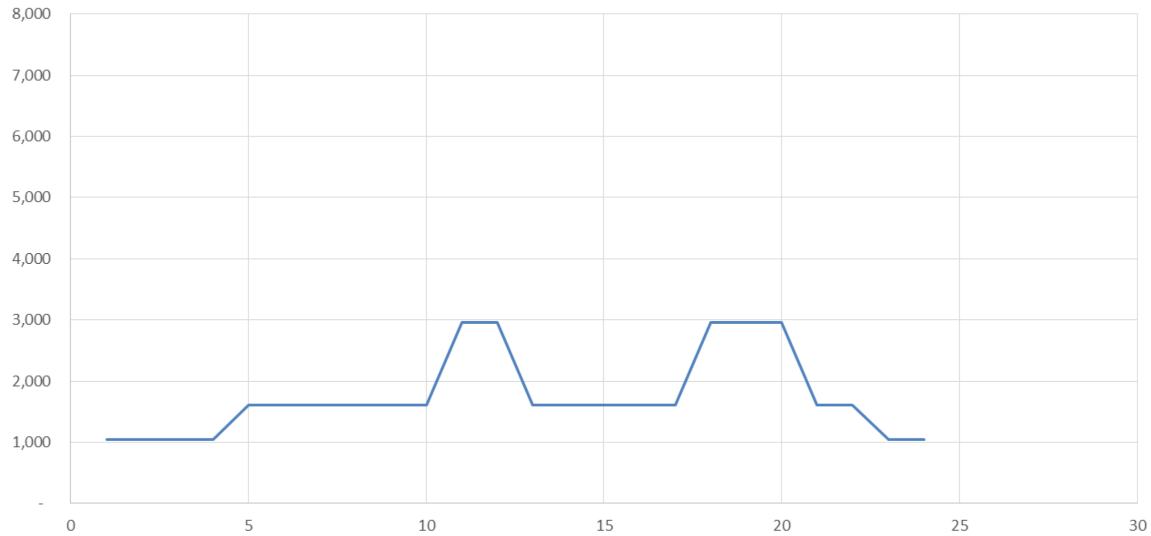
- When program is launched, monitor actual outcomes, conduct ex-post CBA, and adjust as needed

18.3 Simplified numerical simulation for the determination of a CPP tariff

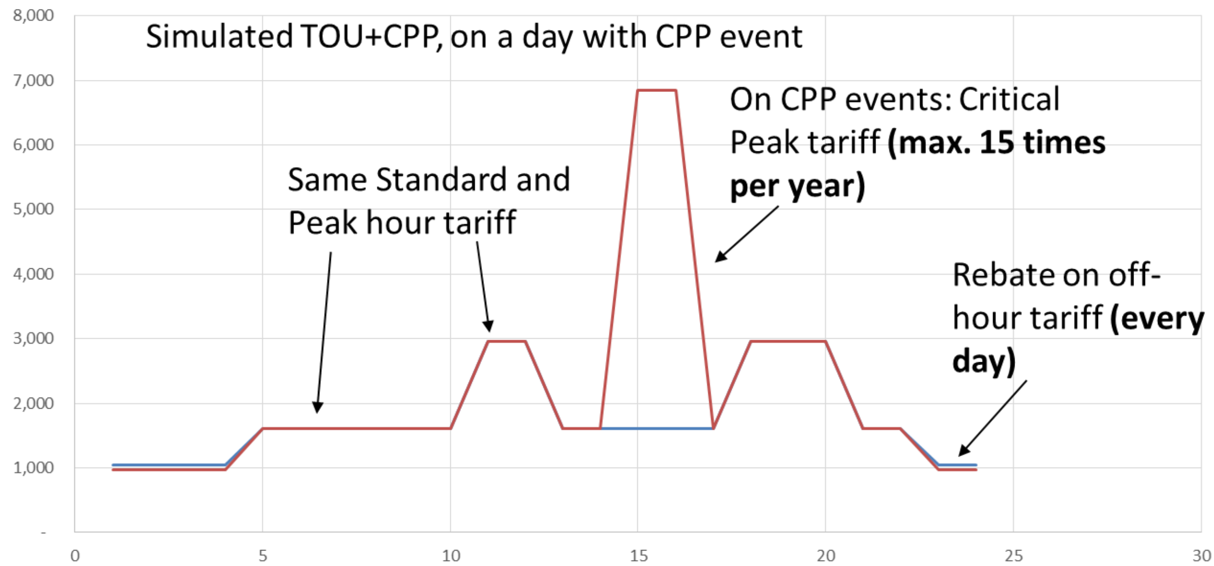
We simulated a CPP tariff program for C&I customers in order to present possible results of what a CPP tariff could look like. CPP events would occur up to a maximum of 15 times per year when system costs are at their highest, and would consist of a tariff many multiples the regular rate, to incentivize demand response from customers participating in the program. In exchange, these customers would be offered a reduction from their regular electricity rate.

18.3.1 Principles of the program design

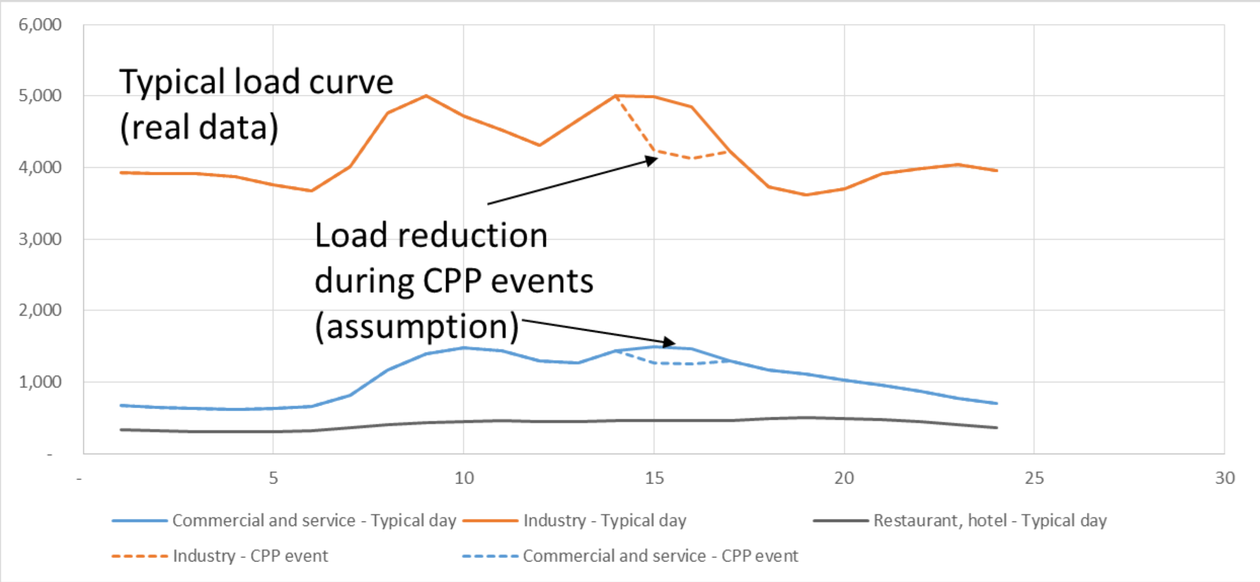
The below graphic shows the existing TOU tariff for commercial and industrial customers, with the off-peak tariff, standard tariff, and on-peak tariff.



The below graphic shows the possible simulated tariff on a day with a CPP event, including the off-peak tariff, standard tariff, on-peak tariff, AND the critical peak tariff.



The below graphic shows assumed customer behavior during a CPP event compared to the base case. The solid lines show the typical commercial (blue) and industrial (orange) customer behavior without a CPP event, and the dashed lines show customers' demand response with a CPP event.



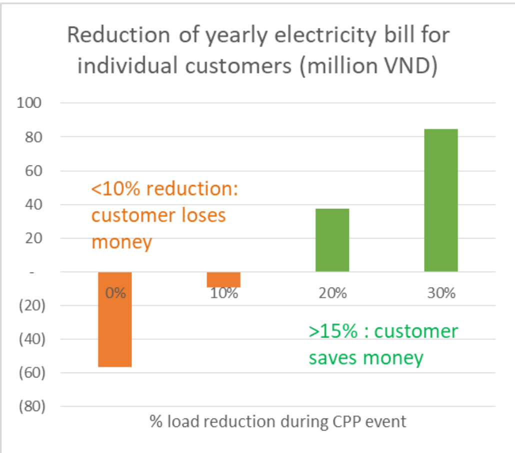
18.3.2 Assumptions

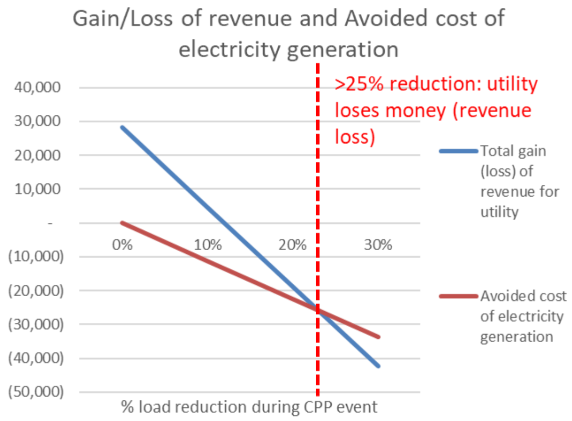
We have assumed the following assumptions in our numerical simulation of a CPP tariff program:

- **Enrolled customers**
  - 500 Industry customers
  - Tariff category: Manufacturing, 6-22kV
  - Average peak load 2000 kW per customer
- **Program costs**
  - Monthly cost per customer 45,000 VND
  - Monthly fixed program cost 115,000,000 VND
- **Avoided costs**
  - 3,850 VND/kWh
- **Up to 15 CPP events per year**
- **Duration 2h to 4h**
  - For the simulation, we simulated four different types of events, lasting 2, 3 or 4h, happening during Standard hours or Peak hours
- **Price of electricity during Critical Peak**
  - 5x standard hour tariff (PoPP=5)
- **Rebate offered to participating customers**
  - -8% on off-peak hour tariff, every day of the year (even on days without CPP events)

18.3.3 Indicative Results and Key Findings

The simulation shows that there is an ideal percent reduction to maximize benefits to ensure a positive benefit-cost ratio. Thus, the benefit-cost ratio depends on consumer behaviour. With less than a 10% load reduction during CPP events, the program would make the consumer worse off as they would have to pay more overall for their electricity bill (compared to a scenario without the program). A 15% and greater load reduction during CPP events makes consumers better off, as they save money overall on their electricity electricity bill. However, a load reduction of 25% or greater entails a revenue loss for the utility, as the revenue loss from customers becomes higher than the benefits (cost savings) of the program. The figure below illustrates this in graphical form.





The key findings obtained from running the numerical simulation are presented below:

- The benefit-to-cost ratio of CPP is sensitive to many factors:
  - Customer behaviour
  - Actual cost of avoided electricity generation
  - Number of events taking place
- The design parameters (Peak-to-Off-peak and Rebate) must be differentiated for each type of customer, depending on load curve
- Moving forward, the following is needed:
  - Collect more data on customer behaviour and preferences
  - When program is launched, monitor actual outcomes, conduct ex-post CBA, and adjust as needed

APPENDICES

19 APPENDICES

19.1 APPENDIX A: Decision 54 (54/QD-DTDL 12 June 2019)

Calculation of Baseline Load Curves

The base load is built and determined on the basis of a set of average power values of customers participating in the program on a 30-minute cycle.

The average load capacity of customers participating in the program on a 30-minute cycle is calculated by arithmetic mean using the following formula:
B [D, t] = 1 / (5) x (P [D1, t] + Pm [D2, t] + Pm [D3, t] + Pm [D4, t] + Pm [D5, t])

The base load curve in the period of the load adjustment event in day D is built on the basis of the set of values B [D, t] as:
B (D, T) = {B [D, t]}

Where :

- D: The expected working day of the Load Adjustment Event;
- D1, D2, D3, D4, D5: 5 consecutive working days before D-1, where D1 is the consecutive working day before D-1. In case of 5 consecutive working days before D-1 there are days that happened the adjustment event, the days must be excluded and replaced with consecutive working days before D5. to have enough data of 5 working days for calculating the customer's Baseline load during the load adjustment event taking place in the working day D;
- T: The period of time that the load adjustment event takes place;
- t: A cycle every 30 minutes / time during (T) event of adjustment of electric load in working day D;
- B [D, t] (in kW): The average load capacity of customers participating in the program at cycle (t) in the working day D;
- Pm [D1, t], Pm [D2, t], Pm [D3, t], Pm [D4, t], Pm [D5, t] (in kW): Average load capacity of Customer join the program at the time of the cycle (t) of 5 consecutive working days (D1, D2, D3, D4, D5) before D-1.

The average load capacity of customers participating in the program at cycle (t) of working day Di is determined as follows:
Pm [Di, t] = (A [Di, t]) / 0.5

Where:

- Di: Working day (i) in 05 consecutive working days before D-1;
- A [Di, t] (in kWh): Electricity consumed in cycle (t) of the corresponding Di working day, collected from the electricity measurement system of customers participating in the program.
- Notes: this method of calculating the Baseline Load Lines applies equally to the CLP Program and EDRP Program.

Calculation of Adjustments and Incentives

Capacity calculation
The average load capacity of the customer participating in the program at cycle (t) in the period (T) of day (D) is determined as follows:

P [D, t] = (A [D, t]) / 0.5
Where:

- P [D, t] (in kW) is the average load capacity of the customer participating in the program at cycle (t) in the period (T) of day (D).
- A [D, t] (in kWh) is the power consumption collected from the electronic meter of the customer participating in the program at cycle (t) in the period (T) of day (D));
- The average adjustment capacity of customers participating in the program at cycle (t) in the period (T) of day (D) is determined in the following cases:

a. In case P [D, t] ≥ B [D, t] then ΔP [D, t] = 0;
b. in case P [D, t] <B [D, t]:
then ΔP [D, t] = B [D, t] - P [D, t] if CLP Program limit or EDRP Program limit is greater than the difference in (B [D, t] - P [D , t]);
or ΔP [D, t] = CLP Program limit or EDRP Program limit, if the CLP Program limit or EDRP Program limit is greater than the difference in
(B [D, t] - P [D,t]).

- In case the Customer participates in the program but decides not to participate in the event, ΔP [D, t] = 0.

Reduced Power Output Calculation
The reduced power output of the customer participating in the program according to the cycle (t) in the period (T) of day (D) is determined as follows:

[A [D, t] = ΔP [D, t] x 0.5

The reduced power output of customers participating in the program during the period (T) of day (D) is determined as follows:

$$\Delta A[D,T] \ = \sum_{t=1}^{n} \Delta A[D,t)$$

Incentive calculation
The incentive amount to be paid to CLP customers is calculated on a cycle (t) within a period of (T) of day (D), and determined as follows:

K [D, t] = ΔA [D, t] x g [D, t]
Where:

- K [D, t] (VND) is the incentive amount that customers participating in the program receive based on the cycle (t) in the period (T) of day (D);

- g [D, t] (VND / kWh) is the incentive for customers to join the program at the time of cycle (t) within (T) of the day (D) issued by the competent authority.

The incentive amount that customers participating in EDRP program is calculated on the cycle (t) in the period (T) of day (D), and determined as follows:

K [D, t] = ΔA [D, t] x g [D, t] x k [t]
Where:

- k [t] is the incentive coefficient for customers participating in EDRP at cycle (t) within the period (T) of day (D) issued by the competent authority.

The incentive amount that customers participating in the program within a period (T) of day (D) is determined as follows:

$$K[D,T] = \sum_{t=1}^{n} K[D,t]$$

19.2 APPENDIX B: Stakeholder Consultations Summary (14-18 February 2020)

The Consultant had the opportunity to ask stakeholders questions directly respecting the 2019 "dry run" year during its visit to Vietnam from February 9-14, 2020 to conduct consultations and gather feedback from stakeholders. The list of stakeholders to consult was prepared by ERAV and GIZ, and included visits with the parent EVN corporate team, 4 of the PCs, EVNHANOI, ENVCPC, EVNSPC, EVNHCMC, and the Ministry of Finance. For all the meetings ERAV and GIZ were present.

Consultations with EVN and PCs

For EVN companies, the purpose of these discussions was to learn more about the 2019 demand response events and gather lessons learned and assess the state of readiness to ensure successful DR scale up.

Below we summarize the main issues that were discussed during consultations in relation to the 2019 DR events and future design of DR programs.

Policy Readiness

- → All distributors agreed that DSM/DR regulations are ready, that a clear road map has been issued, however they all underscored the lack of policy directions related to financial mechanisms.

Participation levels

- → DR programs are voluntary, so marketing them to potential participants is difficult.
- → The government media and press agencies should intensify efforts to help market DR programs.
- → The lack of financial mechanisms negatively impacts participation levels and could potentially jeopardize the success of the program in the long run as DR events augment as per government plan.

Baseline and Measurement and Verification

- → While positive mechanisms in the form of incentives are necessary, so are negative ones in the form of penalties, as customers may sign as participants but not participate in the DR event when called.
- → One utility in particular commented that the DR events did not correspond to their peaks.

Technological Readiness

- → All PCs commented on the new DR software tool DRMS developed by EVN. Running DRMS showed that the tool works well, but missing a major functionality, namely the cost/pricing one, so utilities can't actually see peak pricing.
- → A couple of distributors commented on the lack of appropriate metering, communication equipment on the customer end.

Communication

→ ALL PCs commented on the lack of communication from NLDC, and that in spite of its central role as system operator and planner, DR planning and the basis for running them at particular times not clearly explained to the various parties.

Consultations with MOF

The meeting with MOF specifically focused on Letter 10192 /BCT-TKNL from MOIT to MOF dated 31/12/2019 containing Comments on the Development of an Energy Service Market and Demand-side Management. The letter is an open invitation to MOF to answer and resolve the issue of the design of DR financial mechanisms which is the last standing major implementation hurdle to full scale national rollout. The Consultant met with the Department of Corporate Finance. We noted the absence of the Department of Accounting, which may have shed further light on the issues on the table that relate to regulatory accounting and cost recovery through tariffs. On 27 March 2020, MOF provided its reply in Letter 3609/BTC-TCDN titled Comments on Some Issues Related to the Development of the Energy Service Market and Demand-side Management

19.3 APPENDIX C: EVNHANOI Report on 2019 DR Implementation

1. Power supply in Hanoi

- 2,581,284 customers in Hanoi, of which:

  + Residential customers: 2,344,380;

  + Non-residential customers: 236,904.

- Total sale of 2019: 19,520.444 million kWh, growth rate 8,98% compared to 2018; split as follows:

  + Agriculture – forestry – fisheries: 315.576 million kWh (1,62%);

  + Industry – Construction: 5,847.054 million kWh (29,95%)

  + Commercial – service – other business: 1,443.694 million kWh (7,40%);

  + Residential and household: 10,622.958 million kWh (54,42%);

  + Other: 1,291.161 million kWh (6,61%).

- Average power tariff 2019: 2,052.32 VND/kWh; increase 121.71 VND compared to 2018.

2. Implementation of DR program

- Implementing the policy of the Government and the guidance of EVN related to implementation of DR program in 2019, EVN-HN has implemented the program in the city.

  + Establishing Steering Committee, working group for DSM program under EVN-HN to implement, supervise the implementation of DSM program.

  + Guide member companies to conduct surveys on the situation of power consumption, the ability to participate in DR program and sign agreements to participate in the program to manage non-commercial load with key energy users, large power consumers in Hanoi city.

  + Organize training, awareness raising events for unit leaders, officials and employees in EVN-HN about the key contents of the DSM program, DR program; policies on DMS / DR, executive directives of senior manager ...

  + Propagating and surveying the possibility of participating in the DR program for all customers in Hanoi city.

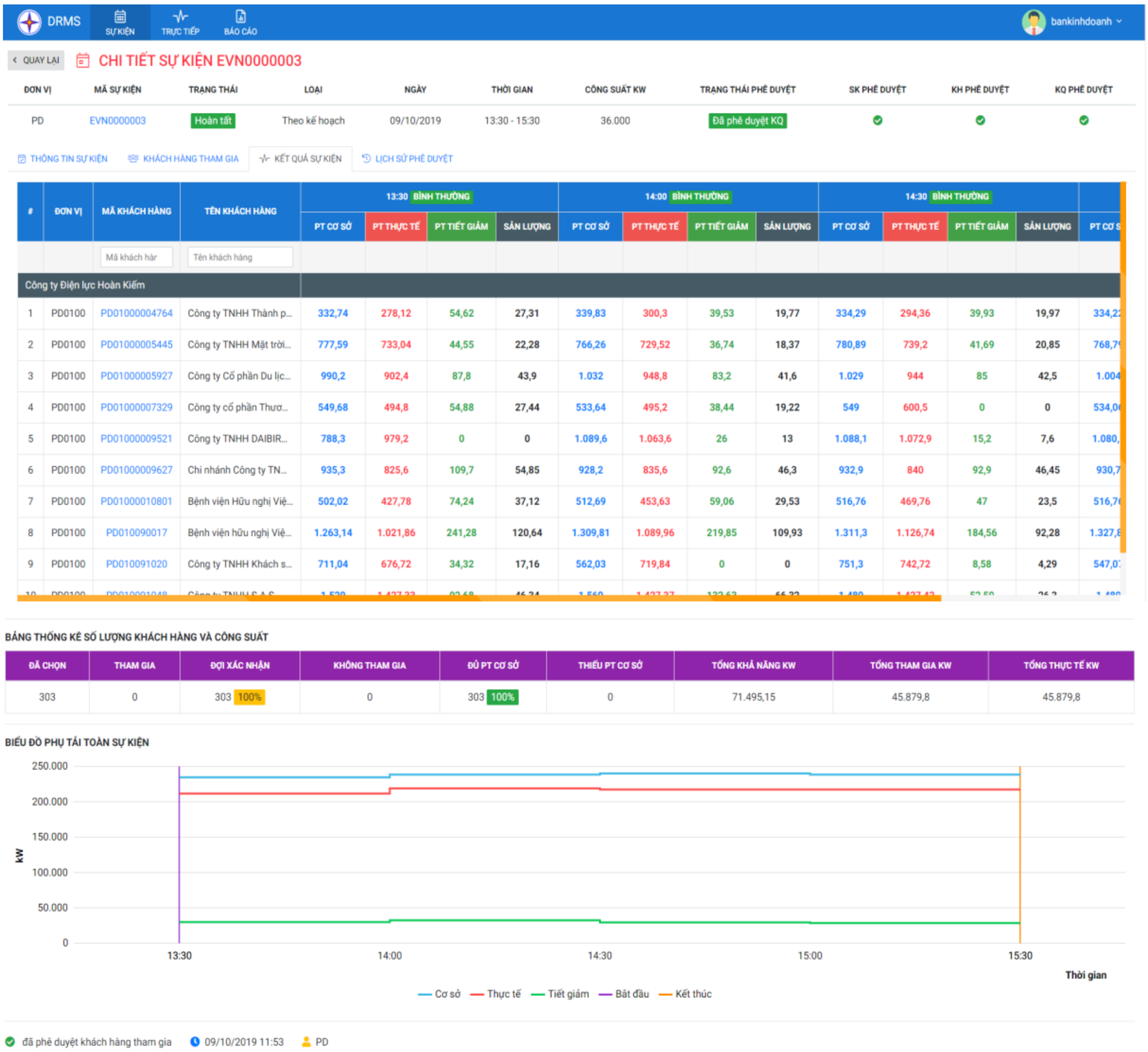
  + Develop guidelines on the order and procedures for DR in EVN-HN according to the circulars of MOIT and guidelines of EVN.

  + Deploying software (DRMS) at EVN-HN; connect customer data system from CMIS3.0 system, telemetry system, EVNHES, MDMS to the program; update information of customers who have agreed to participate in DR program and deploy training, guide users.

  + Up to now, 485 customers have agreed to join the DR program, with a total registered reduction capacity of 88.24 MW.

+ In 2019, EVN-HN organized 03 DR events in July, September, October with 731 turns of customers participating in the events, the total capacity reduced was 82.84 MW, equivalent to 165.68 MWh of electricity output during the event.

+ The management activities of customer participating in the DR program, the implementation of DR events have been operated by EVN-HN on DRMS software from customer selection steps, event notification to customers, calculation of base load, calculation of reduced capacity under DR event.



- Deploying load study, building and analyzing load chart of typical customers for DR implementation; building 3,793 samples of customers of additional components, of which 437 customers are public stations representing residential electricity users (4401, 4402) and 3,356 non-residential customers.

- Develop plans and deploy construction, installation of rooftop solar power systems at the locations of the headquarters of Power Companies, 110 and 220kV transmission transformer stations. Currently, EVN-HN has implemented the installation at 03 locations of the Corporation headquarter and units with a total installed capacity of 80.8 kWp.

- Conduct awareness raising for customers on energy efficiency and conservation; EVN-HN has carried out propaganda about the rooftop solar power program on the Corporation's and Power Companies' Website. So far, there have been 457 customers installing solar power and registering to connect the grid, selling electricity to EVN-HN with a total installed capacity of 3.36MWp; The accumulated electricity output generated to the grid is 474,579 kWh.

3. Advantages and disadvantages of DR program

- As one of the government's key programs, the DR program is the attention and guidance of the leaders: ERAV, People's Committee of Hanoi City, Department of Industry and Trade Hanoi.

- Power companies have good relationships with customers in the area, especially for industrial customers.

- It is a new program that takes a lot of time to communicate and propagate to customers to understand the benefits brought to customers and the community from which to respond.

- At present, EVN in general and EVN-HN in particular are implementing a non-commercial DR program, the mechanism of encouraging customers to participate does not have obvious economic benefits, so many customers do not agree to participate. The majority of clients recommend a specific financial mechanism when customers participate in DR programs.

4. Recommendations

- Proposing the Government to promulgate specific financial mechanisms for customers participating in the DR program.

- Proposing the ERAV to consider, study, elaborate and DR selling prices over time according to the actual load used in the region. Currently, the peak time of the area has a lot of movement compared to the prescribed time frame, for example, the summer peak load is gradually moving to the period of 21:00 to 23:00.

19.4 *APPENDIX D: ERAV Summary Notes from Meeting with MOF on 9/9/2018 to Discuss Letter 6309*

The results after working with Department of Corporate Finance in 9/9/2018: Difficulties in financial mechanism for ESCO and DSM (according to letter 6309/BCT-TKNL in 9/8/2018).

A. Proposal to MOF: "to enact financial mechanism and encourage mechanism to customers to participate in DSM", including:

1. Allow EVN to record the costs of implementing energy saving programs and DSM on electricity prices, using production and trading costs of EVN (or each kWh electricity saved directly, EVN will be permited using the expense equal or equaivalent to ...% generation costs of 1kWh electricity).

Answer: Under the clause 2(k) Article 9 Decree No. 218/2013/ND-CP of Prime Minister dated 26/12/2013 on detailing and guiding the implementation of Enterprise Income Tax Law: "The expenses are not corresponding to the taxable revenues, with the exception of special cases complying with MOF guideline". The expenses must be deducted while calculating taxes, not record to the reasonable and valid expenses, as if regulating the tax-deductible when calculating enterprise income tax "not included in expenses".

2. Allow EVN to pay electricity bills (for implementation of Demand Side Response programs) to customers through electricity bills based on the compensation principle.

Answer: it will not to do since/as Article 7(1) and Article 8(8) Circular No. 219/2013/TT-BTC (unclear, need to review and verify).

B. Proposing MOF to issue financial mechanism to encourage ESCOs development, providing more energy saving services, detailing:

1. Financial support mechanism (preferential loans from state-owned and commercial banks; establishment of new fund to support and develop ESCO projects, guarantees, etc.).

Answer: unfeasible according to Law on credit institutions. Under Decree No. 32/2017/ND-CP, ESCO and DSM are not listed to supporting preferential loans from Vietnam Development Bank. According to Circular 01/2018, you do not create a new mechanism without identifying the source. If ESCO is a small and medium-sized enterprise, it can potentially borrow the loans with preferential interest rate under Decree 34/2018... dated 18/3/2018. (supporting sources for SME).

2. The payment and finalization mechanism/guideline of energy saving costs for non-business administrative units (using the state budget) will be applied the energy saving solutions provided by ESCO.

Answer: Payment and finalization mechanism of energy saving expenses for the non-business administrative units? Unclear to visualize the principles and mechanism of ESCO operation. Need to study and clarify the recommendation.

3. Allow EVN to hand over all initial assets of ESCO implementation to customers (after having all payback on investment capital), without implementation the auction mechanism as the existing regulations.

Answer: No, because of Law on Management and Utilization of State capital invested in the enterprise's manufacturing and business activities and Decree No. 10/2017/ND-CP promulgating the regulation on financial management of Vietnam Electricity Corporation and amending and supplementing Clause 4, Article 4 of Decree No. 209/2013/ND-CP dated December 18th, 2013 of the Government detailing and guiding the implementation of a number of articles of the Law on Value-Added Tax. MOF also has had written to EVN before.

4. Allow EVN to collaborate with both capacity and experience partners locally and internationally by using business cooperation contract in order to carry out energy saving and DSM projects.

Answer: Yes, EVN complies with existing regulations. Ensure the principle that capital derived must be preserved (under Article 10(5) of Decree No. 10/2017/ND-CP dated 9/2/2017 on the financial management regulations of EVN and BCC provisions).

19.5 APPENDIX E: Numerical Simulation Spreadsheets

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