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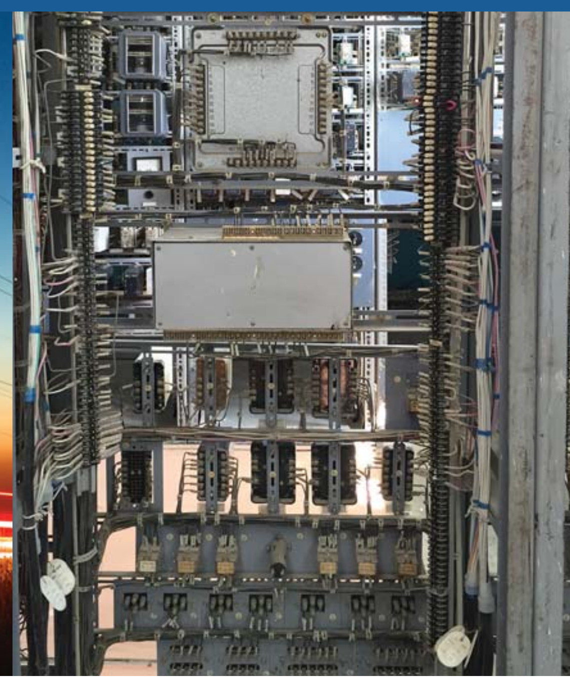
Smart Grid to Enhance Power Transmission in Vietnam





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Acknowledgements

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Executive Summary

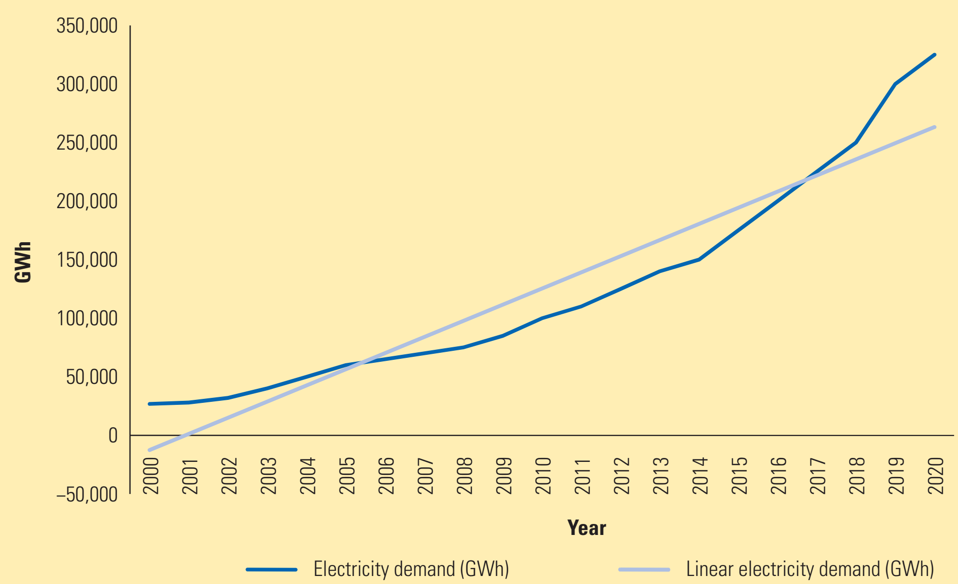
Over the last few decades Vietnam has made remarkable progress in reducing poverty and positioning its economy on a sustainable growth path. Political and economic reforms (Doi Moi) launched in 1986 have transformed Vietnam from one of the poorest countries in the world, with per capita income below $100, to a lower middle income country within a quarter of a century with per capita income of over $2,000 by the end of 2014. Vietnam's growth rate has averaged 6.4% per year for the last decade and the percentage of people living in poverty dropped from almost 60% in the 1990s to less than 3% today.

As a consequence of robust economic growth, electricity demand in Vietnam grew at an average of 14% annually over the last decade. Despite the recent economic slowdown, post-2009 electricity demand has continued to grow 10% annually reaching 119 billion kWh in 2012 and is anticipated to increase to 320 billion kWh in 2020 and 690 billion kWh in 2030 respectively. Per capita electricity consumption remains low in Vietnam at 1,035 kWh in 2012 compared to 2,224 kWh in Thailand and 2,942 kWh in China. Figure 1 shows the development of electricity demand and official demand forecast as presented in Vietnam's Power Master Development Plan (PMDP) VII.

With electricity consumption nearly matching generation in recent years and insufficient investment in new power plants, the electricity grid is under constant strain by the growing economy. Realizing the large technical, institutional and financial challenges posed by this level of expansion will be a key priority for Vietnam's grid system operators in the short term. Moreover, the planned addition in the longer term of renewable energy technologies to the energy mix will pose further challenges to the efficient delivery of electricity to a growing customer base. Facing these challenges will require the adoption of innovative solutions such as the ones provided by Smart Grid technologies.

In 2012, the Government of Vietnam (GoV) approved the "Smart Grid Development Project in Vietnam" which outlines a Smart Grid Roadmap for Vietnam. The Project is aimed at the integration of new monitoring, protection and control systems to improve grid reliability and make efficient use of infrastructure while facilitating future

FIGURE 1 VIETNAM'S ELECTRICITY DEMAND



Source: Vietnam PMDP VII.

TABLE 1 TECHNICAL BENEFITS OF SMART GRID TECHNOLOGIES

Smart Grid Initiative	Technical Benefits
SAS, including remote control centers	60% reduction of OPEX[1] for the transmission system Average reduction of ENS[2] by 100 MWh/y per substation equipped
WAMS	10% reduction of OPEX for the transmission system 20% less faults if all substations are equipped with PMUs[3]
LLS	5% reduction of OPEX for the transmission system 25% reduction of phase-to-phase-to-ground faults caused by lighting
SVC	10% reduction of OPEX for the transmission system 25% reduction of voltage collapse events
FLS	25% reduction in time taken to attend and repair the fault
DGA	80% of faults prevented by equipping a transformer with a DGA device
DTCR	5% reduction of OPEX for the transmission system
GIS	10% reduction of total OPEX of the SAS project
Power Quality Monitoring and Metering Data Acquisition Systems	5% reduction of OPEX for the transmission system 20% reduction of fault times

Source: Authors

Notes:

1 Operational Expenses

2 Energy Not Served

3 Phase Measurement Units

integration of scaled-up renewable energy options. The National Power Transmission Corporation (NPT) has already started progressing some of the Smart Grid initiatives for transmission identified in the roadmap, such as, the deployment of Substation Automation System (SAS) and Wide Area Monitoring Systems (WAMS) as well as an information system for operation and supervision.

To support GoV's efforts, the World Bank has closely engaged with NPT, the Electricity Regulatory Authority of Vietnam (ERAV) and the National Load Dispatch Center (NLDC) to refine the existing Smart Grid roadmap on the basis of the lessons learned from the international experience with Smart Grid development. This report presents the results of this technical assistance engagement funded by the Energy Sector Management Assistance Program (ESMAP) and the Asia Sustainable and Alternative Energy Program (ASTAE) and consists of: (i) a technical analysis of Vietnam's existing Smart Grid roadmap, and alternative and future options (Volume 1); (ii) cost-benefit and risk analyses of the Smart Grid options identified in the technical analysis (Volume 2); and (iii) considerations of regulatory and performance monitoring (Volume 3).

The report proposes a revised Smart Grid roadmap containing the following components: (i) SAS; (ii) WAMS; (iii) Lighting Location System (LLS); (iv) Static Var Compensator (SVC); (v) Fault Locator System (FLS); (vi) On-line Dissolved Gas-in-oil Analysis (DGA); (vii) Dynamic Thermal Circuit Rating (DTCR); (viii) Geographic Information Systems (GIS); and (ix) Power quality monitoring and Metering Data Acquisition Systems. Table 1 highlights the technical benefits coming from the adoption of these Smart Grid technologies.

In addition to Smart Grid technologies, High Voltage Direct Current (HVDC) technology is also considered in the analysis. The construction of a new HVDC line is not a Smart Grid initiative itself, but the choice of the HVDC technology for building over planned conventional AC lines introduces certain desirable characteristics in the grid to render it more secure. The design of the grid therefore is smart and the incremental benefits associated with the HVDC line over the planned AC line have been considered in the analysis. In particular, the adoption of HVDC can contribute to reduce the transmission system OPEX by 5%.

The cost-benefit analysis performed shows that all identified Smart Grid solutions have positive Net Present Values (NPVs). Table 2 summarizes the results of the analysis for each Smart Grid initiative based on the assumed scale of each operation.

TABLE 2 COST-BENEFIT ANALYSIS OF SMART GRID TECHNOLOGIES

Smart Grid Initiative	Capital Cost (USD mln)	NPV (USD mln)	IRR[4]	Scale of Operation
SAS, including remote control centers	147.9	179.0	41%	18 retrofits 150 new SAS
WAMS	1.3	23.0	204%	224 PMU installed at 500 kV and 220 kV voltage level
LLS	1.4	11.0	164%	20 detectors monitoring lightning activity across the country
SVC	25.0	5.3	14%	900 Mvar SVCs installed in the most affected areas of Vietnam
FLS	7.3	1.2	13%	140 Fault Locators
DGA	41.7	5.5	12%	732 transformers equipped, (includes current and new)
DTCR	1.1	44.1	Positive Cash Flows	40 sensors monitoring 400 km lines
GIS	0.2	0.8	48%	Geographic information of power system components throughout Vietnam
Power Quality Monitoring and Metering Data Acquisition Systems	0.2	11.0	797%	105 power quality measurement devices at 500 kV and 220 kV voltage level

Source: Authors

The cost-benefit analysis of HVDC reported incremental capital costs amounting to approximately $13.3 million and an NPV of about $23.5 million based on a 2,000 MW interconnection for 800 km of length.

The risk analysis shows that the initiatives with the highest relative risk profile are: SAS, WAMS, LLS, SVC, FLS, DGA and Power Quality Monitoring and Metering Data Acquisition Systems. Risk mitigation actions for high-risk initiatives are presented in Table 3.

Risk mitigation actions identified for HVDC are to: (i) engage with the planning department to choose optimal installation sites; (ii) develop a proper system operation strategy to fully exploit the HVDC links; and (iii) perform electricity market studies for the medium and long term in order to better estimate the cost of energy and investigate potential profitable connections with foreign countries.

Following the risk analysis, Key Performance Indicators (KPIs) aimed at carrying out performance and impact monitoring of the Smart Grid Program were identified at three different levels: (i) technical; (ii) economic; and (iii) regulatory. Technical KPIs include performance indicators and threshold level. Economic KPIs are measured against a benefit/cost ratio. Regulatory KPIs are measured on different levels (initiative, system, and program) and consist of measurable deliverables. Table 4 summarizes the technical KPIs.

The performance indicator identified for High Voltage Direct Current technology is Power Factor with an associated technical KPI threshold of 0.7.

The implementation of the Smart Grid roadmap requires a set of activities to be performed by the different participants involved (ERAV, NPT, and NLDC) on the roadmap activities until the completion of the program. As illustrated in Table 5, overall implementation coordination rests with NPT. Together with NLDC, NPT would be responsible for the incorporation of the refined roadmap in high level planning activities. ERAV is expected to play a central role in the final approval of the Smart Grid initiatives identified (which would then be up for inclusion in the Master Plan by the Institute of Energy (IE)) and closely monitor their performance during implementation.

TABLE 3 RISK MITIGATION ACTIONS FOR SMART GRID INITIATIVES

Smart Grid Initiative	Mitigation Action
SAS, including remote control centers	• Link the final commissioning of new substations with the complete commissioning of their SAS equipment • Manage the gap between the roadmap and real installation pace • Streamline the SAS automation installation process to target the most critical areas first. Monitor the performance of the already implemented SAS for a better estimation of the ENS saved and a reduction of the investment uncertainty
WAMS	• Expedite the development of the remote control center • Focus investments on developing applications based on WAMS data • Streamline the Phase Measurement Unit installation process to target the most critical lines. Monitor the performance of the installed PMUs for a better estimation of the faults that can be avoided and a reduction of the investment uncertainty
LLS	• Expedite the development of the remote control center • Focus investments on developing applications fed by LLS data and carry out adequate training for the control room operators to exploit LLS information • Optimize the positioning of the sensors in order to cover the whole network
SVC	• Engage with the planning department to choose optimal installation • Re-locatable SVCs can easily solve the problem of site selections that are either not the best fit for purpose or those sites that are temporarily for purpose • Develop a planning activity for the SVC initiative in order to improve the reactive compensation starting with the most critical areas • Use the first implementations for data collection and reduction of investment uncertainty
FLS	• Expedite the installation for the most critical lines • Manage the gap between the roadmap and real installation pace • Optimize the planning activities in order to implement the FLS on those lines with the highest maintenance cost. Monitor the already implemented FLS's for a better estimation of the average reduction outage time duration that is possible with this initiative
DGA	• Align the final commissioning of new transformers and their DGA equipment • Manage the gap between the roadmap and real installation pace • Optimize the planning activities in order to implement the DGA on those transformers with the highest cost of repair and those with the highest fault probability. Monitor the already implemented DGA's for a better estimation of the benefits that can be obtained with this initiative
Power Quality Monitoring and Metering Data Acquisition Systems	• Expedite the installation on the most critical areas • Develop a clear regulatory policy focused on the relationship with the electricity generation function to ensure maximum synergy under critical conditions • Develop a planning activity for the initiative in order to reduce the unserved energy starting with the most critical areas

Source: Authors

TABLE 4 TECHNICAL KEY PERFORMANCE INDICATORS FOR SMART GRID INITIATIVES

Smart Grid Initiative	Performance Indicator	Satisfactory Threshold
SAS	Energy Not Served (ENS) reduction per year for each substation equipped with SAS	100MWh
WAMS	Voltage collapse prevention	15%-35%
	Out-of-steps prevention	15%-35%
LLS	Percentage reduction of transient faults affecting the lines	20%-30%
SVC	95% variation interval of voltage level of network "pilot nodes"	+/-5% of the rated voltage
	Voltage collapse prevention	15%-35%
FLS	Reduction of time to attend fault site by maintenance crew and elapsed time to repair	25%
DGA	Fault number reduction	80%
DTCR	"Ampacity" increase	5%-25%
GIS	Reduction of management costs	10%-15%
Power Quality Monitoring System	Percentage reduction of voltage dips	20%
Metering Data Acquisition System	Mean square error between the value acquired by the meters and the value calculated by the settlement for the same meters	0.4%-0.8%

Source: Authors

TABLE 5 ROLES AND RESPONSIBILITIES OF THE REFINED ROADMAP

Activity	NPT	NLDC	ERAV	IE
Internally approve the Refined Roadmap	R	R		
Present the Final Report to other institutions	R	I	I	I
Define the priorities for Implementation in the short-term	R	R	A	
Request approval of the Smart Grid initiatives from the regulator	R	R	A	
Approve Smart Grid initiatives	C	C	R	I
Based on the KPIs recommended, define the final targets of KPIs for the implementation	C	C	R	
Include the approved investments in the Master Plan	CA	CI	I	R
Follow up the approved Smart Grid investments through the KPIs	CI	CI	R	

Source: Authors

R = Responsible; A = Accountable; C = Consulted; I = Informed

Finally, the legal and regulatory environment for the revised Smart Grid roadmap was analyzed in the areas of: (i) System Security policy; (ii) Renewables and their policies and incentives; (iii) International Interconnection policy; (iv) Quality of Service regulatory policy (indicators, incentives, penalties); and (v) Smart Grid Policy. The main recommendations are summarized in Table 6.

TABLE 6 LEGAL AND REGULATORY RECOMMENDATIONS

Policy Area	Recommendation
System Security policy	The Grid Code should be complemented by the on-line security assessment criteria in order to avoid repeating past errors. Additionally, it should establish the tools that the System Operator must have in order to evaluate the security and perform on-line monitoring and control of the voltage/dynamic stability of the Vietnamese Power System.
Renewables and their policies and incentives	Renewable energy planning should complement the developed Smart Grid roadmap in order to take advantage of those applications that ease the integration of renewable sources in the transmission network.
International Interconnection policy	A greater degree of clarity in this area is needed. This may have some significance for the development and deployment of some of the Smart Grid initiatives, e.g., HVDC interconnection, more stringent requirements for online monitoring and security assessment to ensure frequency/voltage problems do not cascade from one system to another, etc. A policy that addresses these points may enable the inclusion of technologies like HVDC and increment the use of SVC for maintaining the stability of the systems and links.
Quality of Service regulatory policy (indicators, incentives, penalties)	The Grid Code should be revised to include clearly defined penalties for failing or incentives for exceeding quality of service requirements.
Smart Grid Policy	The Smart Grid policy should complement Decision No.: 1670QĐ-TTg of November 2012 with both KPIs and penalties in order to measure and track the performance of Smart Grid initiatives.

Source: Authors

1

Volume 1: Technical Analysis

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A. Acronym List

AC	Alternate Current
AMS	Asset Management System
AVR	Automatic Voltage Regulator
CCPP	Combined Cycle Power Plant
CEER	Council of European Energy Regulators
CRLDC	Central Regional Load Dispatch Center
CT	Current Transformer
DC	Direct Current
DGA	Dissolved Gas-in-oil Analysis
DLR	Dynamic Line Rating
DSA	Dynamic Security Assessment
DTCR	Dynamic Thermal Circuit Rating
EMC	Electro-Magnetic Compatibility
EMS	Energy Management System
EPRI	Electric Power Research Institute
ENTSO-E	European Network of Transmission System Operators for Electricity
ENS	Energy Not Served
ERAV	Electricity Regulatory Authority of Vietnam
EVN	Electricity of Viet Nam
FACTS	Flexible Alternate Current Transmission System
GIS	Geographic Information System
GIS	Gas Insulated Switchgear
GOOSE	Generic Object Oriented Substation Event
GPS	Global Positioning System
GUI	Graphical User Interface
HIS	Historical Information System
HVDC	High Voltage Direct Current
ICCP	Inter-control Centre Communication Protocol
IED	Intelligent Electronic Device
IEM	Internal Energy Market
ISO	Independent System Operator
IE	Institute of Energy
LAN	Local Area Network
LLS	Lightning Location System
LSA	Line Surge Arrester
MPI	Ministry of Planning and Investment
MOIT	Ministry of Industry and Trade
NASPI	North American Synchrophasor Initiative
NYPA	New York Power Authority
NERC	North American Electric Reliability Corporation
NLDC	National Load Dispatch Centre
NPT	National Power Transmission corporation
NRLDC	Northern Regional Load Dispatch Center
OHTL	Over-Head Transmission Line
PDC	Phasor Data Concentrator
PMU	Phase Measurement Unit
POW	Point Of Wave
POD	Proper Orthogonal Decomposition
PQ	Power Quality
PSS	Power System Stabilizer
PTC	Power Transmission Company
RES	Renewable Energy Source
RFI	Radio Frequency Interference
RTU	Remote Terminal Unit
SAS	Substation Automation System
SCADA	Supervisory Control And Data Acquisition
SGDP	Smart Grid Demonstration Program
SGIG	Smart Grid Investment Grant
SO	System Operator
SPS	Special Protection Schemes
SRLDC	Southern Regional Load Dispatch Center

S/S	SubStation
STATCOM	STATic Synchronous COMpensator
SVC	Static Var Compensator
TLC	Telecommunication
TLSA	Transmission Line Surge Arresters
TO	Transmission Owner
TSO	Transmission System Operator
TCSC	Thyristor-Controlled Series Compensation
UCTE	Union for the Coordination of the Transmission of Electricity
VT	Voltage Transformer
WAMS	Wide Area Monitoring System
WAN	Wide Area Network
WEEC	Western Electricity Coordinating Council

B. Summary of Technical Analysis

B.1 Existing Smart Grid Roadmap and Initiatives

Vietnam Electricity (EVN) is partway through the development of a Smart Grid program, which is aimed at the integration of a new monitoring, protection and control system for enhancing the electrical network.

Running parallel with EVN's program, the National Power Transmission Corporation (NPT) has accelerated its own Smart Grid technology development. The initiatives they are currently progressing are:

a. **Substation Automation System (SAS).** This initiative is comprised of three phases. The first two have already been developed, while the third is ongoing. The three stages deal with:

   i. Digital protection and control using legacy serial and hardwired connections, and in particular, problems with interoperability between multiple manufacturers' Intelligent Electronic Device (IEDs).

   ii. Specifications for SAS aimed at improving IED compatibility. UCA2, Modbus TCP, DNP TCP and IEC 60870-5-104 were chosen as substation LAN communication protocols between Host Computers and the IEDs or NIM (Network Interface Modules). The IEC 60870-5-101 protocol was chosen for the transfer of data from a substation's real time database to the existing SCADA system.

   iii. Installation of digital equipment and the adoption of the IEC 61850 protocol for LAN communications. The IEC 60870-5-101/104 will be used instead for communication between the SAS and the Remote Centre, i.e. the Information System for Operation and Supervision of the NPT networks.

b. **Information System for Operation and Supervision**. This initiative aims to create an Information Centre to support remote operation of the substations and the first instance of remote operations will be in place by the end of 2015. The SCADA/EMS System of the NLDC and the Information Systems of the NPT will collect information in parallel from the field and will be able to exchange data by means of a direct link using the ICCP protocol.

c. **Wide Area Monitoring Systems (WAMS) - Pilot project**. The NPT has developed a customized solution for wide-area measurement that uses the synchrophasor functionality. In particular the HMI solution consists of four applications tailored for specific local uses:

   i. Desktop application for calculating the real-time power transfer capability of the system and providing alarms based on thresholds set by the user;

   ii. MATLAB application for migration of synchrophasor data to a programming environment for performing complex calculations;

   iii. Web application that provides remote access to the data via a secure Internet connection;

   iv. Office productivity applications that provide a data-link interface to the plant information database.

The broader roadmap includes elements of:

a. **Substation Automation System (SAS) upgrade**. This initiative addresses the development of all the new substations that are going to be installed (150 from 2016 to 2030).

b. **Communications Infrastructure for Transmission and Substations.** In order to ensure sufficient and appropriate information is available for the information systems at NPT's head-office and 04 PTCs, it is necessary to develop the North-South information backbone and to connect the WAN network to all substations under NPT's management.

c. **Upgrade Information System**. The main purposes are:

   i. Connecting directly to NPT's substations for acquiring data (Analog, Status information from the substation as well as metering data) and providing data to PTC's Information Systems and data backup for the NLDC's SCADA system.

ii. Integrating WAMS, DTCR, FLS with NPT's and PTC's Information Systems.

iii. Integrating advanced functions such as calculation load flow, stability limit, power capability in real-time (on-line) of transmission network, calculation load flow, fault, stability in offline mode, etc. These will be integrated for operational purposes as well as for planning the implementation of grid optimization, loss reduction and improving reliability.

iv. Exchanging information and data with other parts of the system in Vietnam's Electricity Market.

v. Allowing ease of access for NPT and PTC staff to gather necessary information from anywhere in the electricity network using Web services subject to security controls consistent with international standards and best industry practices.

d. **Metering Data Acquisition System**. NPT has already planned such a project and its purpose is to provide accurate and reliable real-time measurement of energy consumption and supply at all network points where energy is purchased or sold.

e. **Wide Area Monitoring Systems (WAMS).** Only a few PMUs have been installed so far and the WAMS project for the entire 500 kV network is currently considered as a project with a mid-term time scale and a predicted completion sometime in 2022. The project aim is to install PMUs in all 500kV substations under NPT's management and the expected benefits are:

i. Increased system loading while maintaining adequate stability margins;

ii. Improvement of operator response time to system contingencies such as overload conditions, transmission outages, or generator shutdown;

iii. The achievement of advance system knowledge with correlated event reporting and real-time system visualization;

iv. The promotion of system-wide data exchange with a standardized synchrophasor data format;

v. The validation of planning studies to improve system load balance and station optimization.

f. **Dynamic Thermal Circuit Rating (DTCR)**. The key points considered by NPT regarding this initiative are:

i. Dynamic rating and real-time monitoring of transmission lines are being perceived as important tools to maintain system reliability while optimizing power flows.

ii. Dynamic ratings can be considered a low-cost solution to deliver increased transmission capacity. In fact, dynamic ratings are typically 5% to 25% higher than conventional static ratings.

iii. Application of dynamic ratings can benefit system operation by increasing power flow through the existing transmission corridors with minimal investments.

g. **Fault locator system (FLS)**. This project is already underway and six of the most important substations of the 500 kV transmission network will be equipped with FLS devices by the beginning of 2015. Other fault locators will be installed in key substations of the 220 kV network.

h. **Geographic Information Systems (GIS)**. The NPT considers this application as central to ensuring the accuracy and efficiency of the Information System for Asset and Outage Management.

Table 7 provides a summary of the current Smart Grid initiatives that are already in progress under the management of the various agencies of the Vietnamese electricity authorities. The table highlights the key information regarding each of them.

Against this backdrop, the purpose of this document is twofold:

a. To present the international experience of transmission utilities with Smart Grid applications; and

b. To refine NPT's Smart Grid roadmap and produce a new draft version.

B.2 International Experience and Lessons Learned

Developing nations like Vietnam are experiencing rapid growth resulting in a commensurate expansion and enhancement of their energy transmission network. Whilst the electricity authority has taken the initiative and is already implementing or planning a number of Smart Grid applications, there is a risk of disconnection between the somewhat independent initiatives of the various business units that make up the parent organization, the EVN. Thus, in order to ensure coordination

TABLE 7 CURRENT SMART GRID INITIATIVES (ON-GOING AND PLANNED)

Current Smart Grid Initiative	Key information
Substation Automation System (SAS)	• Initiative has reached the appropriate level for this stage of its development. • 150 new substations will be upgraded and brought on-line between 2016 and 2030.
Information System for Operation and Supervision	• The first instance of remote operations will be in place by the end of 2015.
Wide Area Monitoring Systems (WAMS)	• Pilot project developed. • The project aims to install PMUs in all 500kV substations under NPT's management.
Communications Infrastructure for Transmission and Substations	• The North-South information backbone planned. • WAN network to all substations under NPT's management.
Upgrade Information Technology System	• Enhance interconnection of devices with applications.
Metering Data Acquisition System	• NPT has already planned such a project.
Dynamic Thermal Circuit Rating (DTCR)	• NPT is considering such a project for the future.
Fault locator system (FLS)	• This project is already underway and six of the most important substations of the 500 kV transmission network have had FLS devices installed.
Geographic Information Systems (GIS)	• NPT is considering this project as key to the functionality of the Information System for Asset and Outage Management.

Source: Authors

between the efforts of the business units and to maximize the synergy of the applications being deployed as well as filling any gaps in functionality the Vietnamese Smart Grid roadmap will need to be refined to include applications that are not yet integrated within their existing systems.

The applications that fill the gaps in functionality are necessary for the successful implementation of the Smart Grid at a systemic level. On the basis of international experiences a wider view has been adopted to include some solutions that are not usually considered "smart".

Lessons learned from the international experience with Smart Grid development were based on the experiences of the Italian, European and American initiatives. These three cases were selected since they offer a good benchmark for comparison with existing or planned Vietnamese Smart Grid initiatives in general and because they bear some similarity to key issues afflicting Vietnam's transmission network specifically.

In particular the main issues and challenges identified in the Vietnamese transmission system are: (i) network topology issues; (ii) short circuit levels; (iii) miscoordination of protection systems; (iv) defense plan improvements; (v) loadfrequency regulation improvements; (vi) 500 kV limited transient stability; (vii) voltage stability, profile and support/reactive power balance; (viii) lightning performance of exposed 220 kV lines; (ix) SCADA and remote-control centers; (x) time and cost reduction of asset maintenance; (xi) power quality; and (xii) interconnections with neighboring countries.

The first international experience presented is that of Terna, the Italian TSO. The analysis of the Italian experience and subsequent initiatives is particularly relevant to the Vietnamese experience precisely because the long, thin shape of both countries has dictated a very similar north-south electricity distribution topology with a similar concentration of power plants at the extremities of the country.

The Italian experience is particularly helpful, as some of the Smart Grid applications selected for solving key issues and for developing strategies provide a useful starting point and context for the solutions proposed for Vietnam. For example, some parts of the Italian electricity network experienced short circuit levels that exceeded the rated current limit of the circuit breakers, however these problems were satisfactorily resolved by developing appropriate Planning and Asset Management strategies.

Further, as in Vietnam, the Italian network topology exposes the system to transient and voltage stability problems. These issues were among the key drivers for the development the WAMS project. The Italian WAMS experience may prove as useful for Phasor Measurement Unit (PMU) positioning as much as for the kinds of applications developed and the process of progressive integration of WAMS functions in day-to-day systems operations.

The Italian transmission network experience is also very interesting from the perspective of applications such as Substation Automation System, Lightning Location System, Power Quality Monitoring and Metering Data Acquisition System.

Moving from a single country, Italy, to the European electrical infrastructure sets the scene for elaborating a broader example of what constitutes appropriate planning for a large network. The European Commission's ENTSOE Ten-Year Network Development Plan 2014 brought together leading European TSOs in order to establish the guidelines for the development of the entire European network. In particular, this plan focused on addressing transmission investments starting with the identification of bottlenecks across Europe. This process could become the basis of best practice in the future development of interconnections between Vietnam and its neighboring countries. Moreover, this experience highlights the importance of shared N-1 criterion assessment in a large interconnected system.

Reactive Power Compensation in the UK, i.e. by the NGC, represents another important European example of best practice. This refers to the approach adopted by the NGC, to ensure the control and regulation of reactive power exchange and therefore the proper management of the voltage profiles in a transmission system. This was in the context of a significant change in the operation of the grid, due to the substantial unbundling of the assets of the electrical system further compounded by substantial energy input from unpredictable renewable sources. The combination of these factors brought about a need for greater flexibility and a faster response capability in order to overcome the significant complexities of planning and programming the development of the transmission network on a medium/long term basis.

The third and final international experience that is analyzed looks at some key Smart Grid initiatives implemented in the USA. Firstly, the American experience with PMU installations and subsequent development of WAMS applications is very interesting because of their approach, the very high number of applications developed (confirming the potential of WAMS and in particular of the exploitation of PMU data) as well as for the results obtained.

The sophisticated technological level reached by the US transmission systems has resulted in the development of some very advanced Smart Grid applications like Dynamic Rating. Furthermore, thanks to the large number of ISOs and to their differing breadths of scope, there are lessons to be learned from the very different responses to the same problems. Towards this end two dissimilar projects using Dynamic Rating are presented.

The USA transmission system experiences may encourage the introduction of online sensors to predict transformer failures (Dissolved Gas-in-oil Analysis - DGA). This technology is quite widespread but about half of all the devices worldwide are actually installed in the US networks (40,000 of the 80,000 worldwide). A particularly instructive incident at BC Hydro is described in order to understand best practice of this Smart Grid solution. This may provide a good reference to evaluate the opportunity to install sensors for on-line DGA on new and old power transformers.

Another area where new solutions within a transmission network may be of relevance for the Vietnamese grid are those related to a new type of application developed for HVDC systems. Direct Current (DC) technology, in fact, has been used to resolve some problems similar to those experienced by the Vietnamese grid where the primary requirement was an increase in the level of transmitted power to large load areas. Towards this end the TRANS-BAY project for PG & E in California is discussed.

Table 8 presents a summary of the key lessons learned from the international experience.

TABLE 8: KEY LESSONS LEARNED FROM THE INTERNATIONAL EXPERIENCE

Country/ Region	Initiative	Key lessons learned
ITALY	• Some solutions for transmission system enhancement	• A useful starting point for building the future transmission network on a solid foundation.
	• WAMS	• Applications to monitor transient and voltage stability. • PMU positioning techniques.
	• Substation Automation System	• Telecommunication system constraints.
	• Lightning Location System (LLS)	• Guideline for LLS installation. • Benefits for Planning, Asset Management and Operation.
	• Power Quality Monitoring	• Voltage dips reduction. • Identification of protection system malfunctions.
	• Metering Data Acquisition System	• Regulatory implications. • Interface with electricity generation.
EUROPE	• N-1 criterion assessment	• Best practice in the future development of interconnections between Vietnam and its neighboring countries.
	• SVC	• Control and regulation of reactive power exchange. • Management of the voltage profiles.
USA	• WAMS	• Efficient approach to the definition of an applications roadmap.
	• Dynamic Thermal Circuit Rating (DTCR)	• Different available techniques.
	• On-line Dissolved Gasinoil Analysis (DGA) for Power Transformers	• Reference to evaluate the opportunity to install sensors for on-line DGA on new and old power transformers.
	• HVDC	• Possible solution to increase the level of transmitted power to large load areas.

Source: Authors

B.3 Transmission System Enhancements

The second part of this document starts with a gap analysis, which identifies the transmission system enhancements that would enable the successful implementation of the refined Smart Grid roadmap for NPT.

This analysis is based on international best practices vis-à-vis the following pillars:

a. **Planning and Asset Management System basic strategies improvements:** The aim is to drive transmission network expansion in order to overcome present network topology issues.

b. **State Estimation and on-line N-1 Security Assessment:** The aim is to have proposed on-line solutions for expected contingencies; improve the real time knowledge of electrical system status and recommend best practice in preventive and corrective remedial actions.

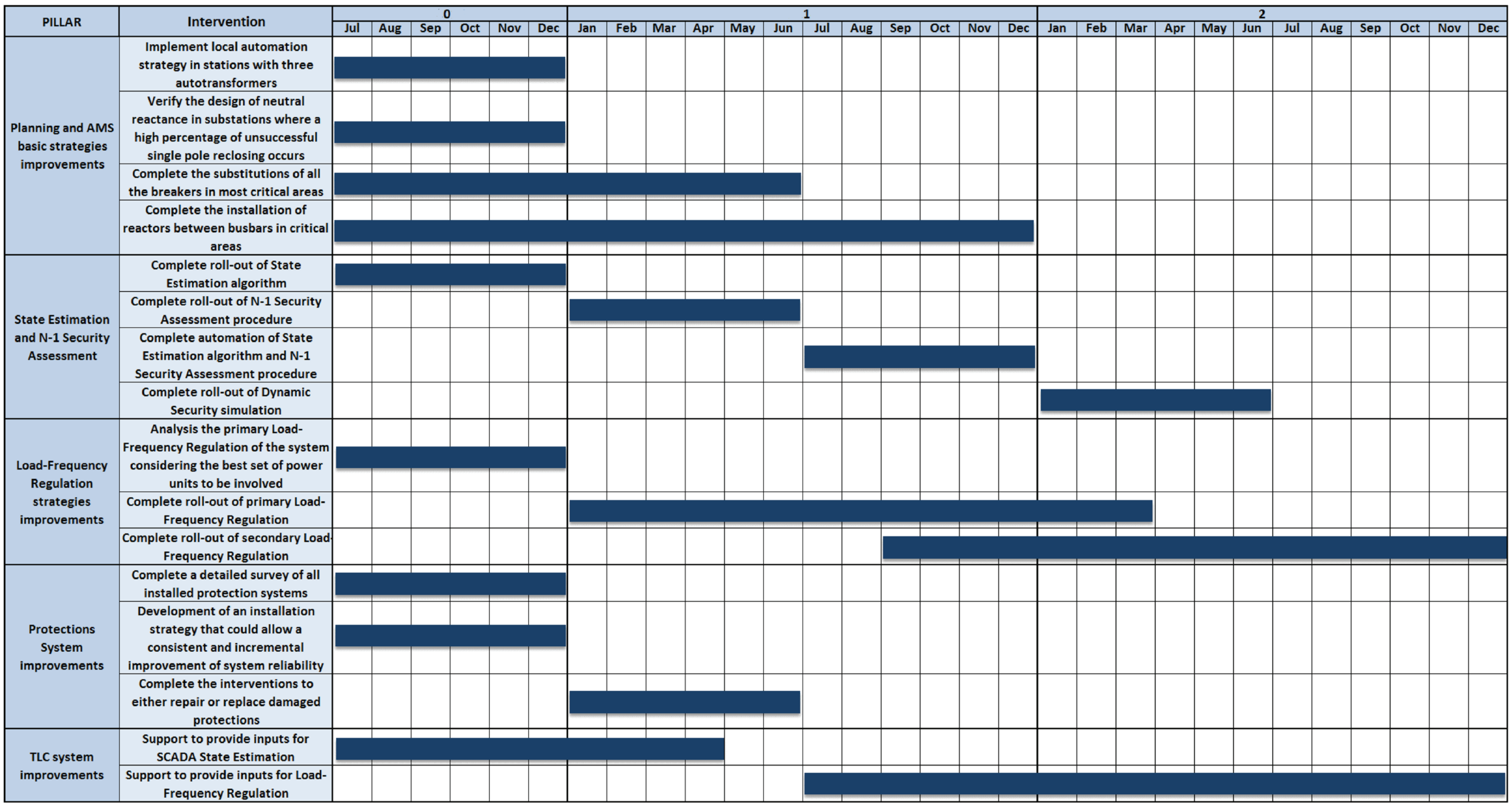
c. **Load-Frequency Regulation Strategy Improvements:** The aim is to guarantee frequency stability and transient support by allocating sufficient primary reserve and also an AGC to overcome any power imbalance due to generation tripping or changes in the imported/exported power levels.

d. **Protections System improvements:** The aim is to equip substations and transmission lines with state of the art digital relays in order to protect against failures and coordinate their intervention by means of inter-tripping logic systems (when required).

e. **Telecommunication System improvement:** The aim is to support the development of the previous initiatives linked with the data communications network.

Deployment of transmission system enhancements is envisioned in the very-short term (two to three years). Figure 4 positions such enhancements on a hypothetical timeline.

FIGURE 4: TIME POSITIONING OF TRANSMISSION SYSTEM ENHANCEMENT INTERVENTIONS



Source: Authors

These interventions are detailed in the document and as they do not require any preliminary activity they can start immediately. The proposed elapsed time of the implementation process for the different interventions is a conservative estimation, based on similar activities performed in other countries (e.g. Italy). It could happen that such elapsed times will be lower than predicted due to some analogous initiatives already planned or underway.

Such time positioning is complemented by a general estimation of associated costs, based on the information gathered and assumptions made about the Vietnam transmission system. Such cost estimates are captured in Table 9. It is worth underlining that for some initiatives no costs are needed. In such cases, the proposed enhancements do not require real investments, but rather imply an improvement in the current practice to exploit existing resources more efficiently.

TABLE 9: COST ESTIMATES FOR TRANSMISSION SYSTEM ENHANCEMENT INTERVENTIONS (SOURCE: AUTHORS)

PILLAR	INTERVENTION	COST ESTIMATION
Planning and Asset Management System basic strategies improvements	Implement local automation strategy in stations with three autotransformers	Negligible in the context of the initiatives already underway for setting-up substation automation systems.
	Verify the design of neutral reactance in substations where a high percentage of unsuccessful single pole reclosing occurs	Negligible in the context of the current work in progress on network maintenance activities.
	Complete the substitutions of all the breakers in most critical areas	The swapping of 30 breakers (at critical points) at a cost of $10,000 each results in a total spend of $300,000.
	Complete the installation of reactors between busbars in critical areas	The installation of 20 reactors at a cost of $40,000 each results in a total cost of $800,000.
State Estimation and on-line N-1 Security Assessment	Complete roll-out of State Estimation algorithm	Negligible in the context of the initiatives already underway for setting-up a new EMS system.
	Complete roll-out of N-1 Security Assessment procedure	Negligible in the context of the current work in progress on setting-up a new EMS system.
	Complete automation of State Estimation algorithm and on-line N-1 Security Assessment procedure	Total cost of $300,000 considering both software purchase and operator training program.
	Complete roll-out of Dynamic Security simulation	Total cost of $300,000 considering both software purchase and operator training program.
Load-Frequency Regulation strategies improvements	Analysis of the primary Load-Frequency Regulation of the system considering the best set of power units to be involved	Total cost of this survey activity is estimated at $200,000.
	Complete roll-out of primary Load-Frequency Regulation Complete roll-out of secondary Load-Frequency Regulation	For hardware and software installation the expense can vary from $30,000 to $60,000 for each power plant. Assuming installation in 40 power plants, the total cost would be between $1,200,000 and $2,400,000.

(Continued next page)

TABLE 9 (CONTINUED)

PILLAR	INTERVENTION	COST ESTIMATION
Protections System improvements	Complete a detailed survey of all installed protection systems	Negligible in the context of the current work in progress on maintenance activities.
	Development of an installation strategy that could allow a consistent and incremental improvement of system reliability	Installing dual protection on 30% of lines at an average cost of $5,000 each results in a total cost of $1,500,000.
	Complete the interventions to either repair or replace unsuitable or damaged protections	Repairing 5% of protection systems at an average cost of $3,000 each results in a total cost of about $150,000 Replacing 5% of protection systems at a cost of $5,000 each results in a total cost of $250,000.
TLC system improvements	Support to provide inputs for SCADA State Estimation Support to provide inputs for Load-Frequency Regulation	Negligible in the context of the current work in progress on setting-up the telecommunication infrastructure.

Source: Authors

B.4 Problems-Solutions Mapping

After identifying transmission system enhancements, an exercise on mapping problems to solutions was carried out. This resulted in mapping Vietnam's network issues and challenges—which are discussed at length in Annex 2—to the above-mentioned pillars, and ultimately to the Smart Grid solutions considered as viable for Vietnam and proposed in the refined NPT Smart Grid roadmap.

A summary of the issues-solutions mapping and challenges-solutions mapping is offered in Table 10 and Table 11 respectively. It is worth noting that in some cases the simple "pillar" implementation is required, while in others only a Smart Grid initiative can solve the problem.

B.5 Technical Prioritization and Revised Smart Grid Roadmap

The solutions identified for the NPT Smart Grid roadmap have been prioritized according to three time horizons: the short term (within the next 5 years), the medium term (within the next 10 years) and the long term (within the next 15 years).

Short-term Smart Grid solutions include:

a. **Fault Locator System (FLS).** A NPT project is already underway and is quite independent from all the other initiatives. It can contribute to time and cost reduction of asset maintenance of the most critical areas of the network with a relatively few number of components. In order to evaluate the success of the FLS initiative, it will be necessary to measure the reduction in the time it takes for a maintenance crew to attend the fault location and the related outage duration (i.e. Mean Time to Repair). The FLS application can be considered satisfactory if after its implementation such times are reduced by 25%.

b. **Wide Area Monitoring System (WAMS).** Besides the fact that NPT has developed a pilot project, WAMS is a solution that could impact many of the other applications (e.g. Dynamic Thermal Circuit Rating) and aims to solve a large number of issues (e.g. voltage and transient stability, defense plans improvements, etc.). The main items in relation to WAMS that are addressed in this document are:

   i. The PMU positioning strategy emphasizing the importance of monitoring not only the 500 KV network but also the 220KV network;

   ii. A brief description of possible WAMS applications useful for the Vietnamese context such

TABLE 10: ISSUES-SOLUTIONS MAPPING

ISSUES	ISSUES CHARACTERISTICS	PILLARS	SMART GRID SOLUTIONS
Network topology issues	• Network highly meshed	• Planning and Asset Management strategies improvements	• Static Var Compensators • Dynamic Thermal Line Rating
Short Circuit Level	• Fault current could exceed the rated current of the breakers	• Planning and Asset Management strategies improvements	• Not Applicable
Miscoordination of Protection System	• Outages due to protection failures • Interference and electro-magnetic compatibility issues on secondary signals	• Protection System improvement	• Power quality monitoring system
Defense Plan improvements	• If the N-1 security criterion is not fulfilled and SPS remedial action is necessary • The security assessment is performed on desk (not on-line)	• State Estimation • N-1 on-line Security assessment	• Substation Automation System • Wide Area Monitoring Systems
LoadFrequency regulation	• Presently this type of regulation is achieved by using one hydro power plant at a time from a maximum of five	• Load-Frequency regulation strategies improvements (AGC)	• Not Applicable
500kV limited transient stability	• High North–South power flow	• State Estimation • N-1 on-line Security assessment	• Wide Area Monitoring Systems
Voltage Stability, Profile and Support/Reactive Power Balance	• High North–South power flow	• State Estimation • N-1 on-line Security assessment	• Wide Area Monitoring Systems • Static Var Compensators
Lightning Performance of exposed lines	• Surge Line Arrester installation without a Lightning Location System	• Not Applicable	• Lightning Location System

Source: Authors

TABLE 11: CHALLENGE-SOLUTIONS MAPPING

CHALLENGES	CHALLENGES CHARACTERISTICS	PILLARS	SMART GRID SOLUTIONS
Monitoring and remotely control the network	• Improve the monitoring, observability and control of the network	• Telecommunication system improvements	• Substation Automation System • Wide Area Monitoring Systems • Metering Data Acquisition System • Geographic Information Systems • On-line Dissolved Gasinoil Analysis for Power Transformers
Time and cost reduction of asset maintenance	• Improve the efficiency of the system	• Not Applicable	• Fault Locator System
Power Quality	• Improve the quality of the system	• Not Applicable	• Power quality monitoring system
Interconnections	• Interconnections with neighboring countries	• State Estimation • N-1 on-line Security assessment • Load-Frequency regulation strategies improvements	• High Voltage Direct Current technology

Source: Authors

as voltage stability monitoring and oscillation detection and monitoring.

Evaluating the success of the WAMS initiative is very complex and it is strictly dependent on the ancillary functions developed using PMU data. For example, a voltage stability monitoring feature based on WAMS can be considered successful if it helps to prevent 15%-35% of voltage collapses. The percentage depends on the topology of the portion of the network involved in the voltage instability event. Equally, a transient stability monitoring function on WAMS can be considered successful if it helps to prevent 15%-35% of power plants falling out-of-step. As with the voltage collapse example, the actual percentage depends on the topology of the portion of the network involved.

c. **Substation Automation System (SAS) (including building/upgrade of substations and building of Remote Control Centers)**. This is a NPT project that has already reached a significant level of development. It has been conducted in synergy with building of Remote Control Centers for unmanned substations since Remote Control Centers constitute a pre-requisite to exploit at best SAS equipment in electrical substations. Their realization is fundamental to position such SAS initiative in the short term. In order to support remote control the development of a communication backbone connecting all the substations under NPT management is a fundamental requirement. The status of the deployment to date is discussed and some recommendations are made in order to optimize the benefits of this solution, especially with regard to interoperability and pre-requisite telecommunication system improvements. Fully digitalized substations, remote terminal units, remote operation and supervision represent the key elements for the success of SAS initiative. The Key Performance Indicator (KPI) for judging the success of this application is the reduction of Energy Not Served (ENS). It can be considered successful if after SAS implementation the average value of faults prevented per year, per substation equipped with SAS is above 1.5. Given the average value of 300 MWh of load losses per fault event, the value of 1.5 corresponds to an average ENS reduction of 450 MWh per year for each substation equipped with SAS.

d. **Lighting Location System**. This is considered as a short-term solution due to the criticality of the lightning problem and the significant number of transient faults incurred on the Vietnamese electricity network. Further, the installation of a Lighting Location System requires quite a long lead time which is why, if the proposed solution is approved by NPT, it should begin as soon as possible. Towards this end, this document presents a guideline for the development of such a system, highlighting the benefits with a particular focus on the installation of Transmission Surge Line Arresters. After the installation of Transmission Surge Line Arresters (guided by Lighting Location System data analysis) the percentage reduction of transient faults can be used as a KPI where a reduction in the range of 20%-30% can be considered satisfactory.

e. **Metering Data Acquisition System.** The NPT project is already underway and it is important to reach a full rollout of this initiative in the near future because it represents the enabling technology for the development of the electricity trading market. The simultaneous installation of SAS may be useful for facilitating the data acquisition process of the Metering Data Acquisition System. It is worth to consider that for the full deployment of such initiative a careful investigation of all the regulatory aspects is fundamental. To evaluate the success of the Metering Data Acquisition System initiative it is worth measuring the mean square error between the value acquired by the meters and the value calculated by the settlement for the same meter. A satisfactory value would lie in the range 0.4%-0.8%.

f. **On-line Dissolved Gas-in-oil Analysis**. It is proposed that all new transformers have this device installed, as its cost is low in comparison with value of the transformer it protects and no particular analysis has to be performed before installing this equipment on new transformers (as mentioned in paragraph 'F.11'). Furthermore, NPT has already started to develop this initiative and it is worth to continue investing in this type of technology on all the transformers that will be installed in Vietnam in the next years. Therefore this initiative has been positioned in the short term. On the other hand, their use with the existing transformer fleet instead will require the identification of the most critical and valuable ones that need to be protected. In fact equipping current transformers with these monitoring devices requires a detailed investigation in order to evaluate the time needed to gather data for the characterization of typical transformer behavior so as to eliminate false positives. The DGA installation initiative can be considered successful if using these monitoring systems a consistent prevention of transformer outages is achieved. A satisfactory value is a reduction by 80% in the number of faults.

Medium-term interventions include:

a. **Static Var Compensator (SVC)**. The main benefits of this type of system are related to possible applications within the Vietnamese transmission grid. SVC systems help to regulate the voltage profile of the 500 kV transmission lines and, with suitable control loops properly integrated with the WAMS applications, to significantly increase the damping of the system during transients particularly in cases of inter-area oscillation. It is important to highlight that before installing SVCs a very detailed feasibility study has to be performed. Making the right choice of locations for SVC devices in the fast growing Vietnamese network will prove to be exceptionally challenging. Towards this end, the use of re-locatable SVC systems is recommended as a possible solution to ensure maximum flexibility for this kind of application in the light of the rapid development of the transmission system and the need to provide timely support for substantial changes and reconfigurations of the grid. The success of a SVC installation can best be judged by measuring the voltage level variations of the most important network nodes (named "pilot nodes"). If 95% (1 σ) of such variations are within +/-5% of the rated voltage the result can be considered satisfactory. Furthermore, as for WAMS evaluation, a SVC can be considered to be operating successfully if it helps to prevent 15%-35% of voltage collapses in the portion of the network influenced by such events.

b. **Geographic Information Systems (GIS).** This cannot be considered as a single Smart Grid initiative in its own right but needs to be seen as a means of enabling other applications. The prior development of other systems like SAS or WAMS could be very useful to plan the implementation of this type of solution to ensure that the largest possible number of applications benefit from this initiative. In order to evaluate the success of the GIS initiative, it is worth measuring the reduction in the management costs of the network. A cost reduction of 10%–15% can be considered a satisfactory result.

c. **Power quality monitoring system**. Power Quality is one of the challenges of the Vietnamese transmission system but it is not considered as one of the most critical. The benefit of this type of system can best be judged by the extent to which it improves power quality levels. This in turn helps to optimize investments in installations aimed at increasing resilience to voltage dips and increasing the ability to promptly identify malfunctioning protection systems. A suitable KPI is the percentage reduction of voltage dips where a value above 20% can be considered satisfactory.

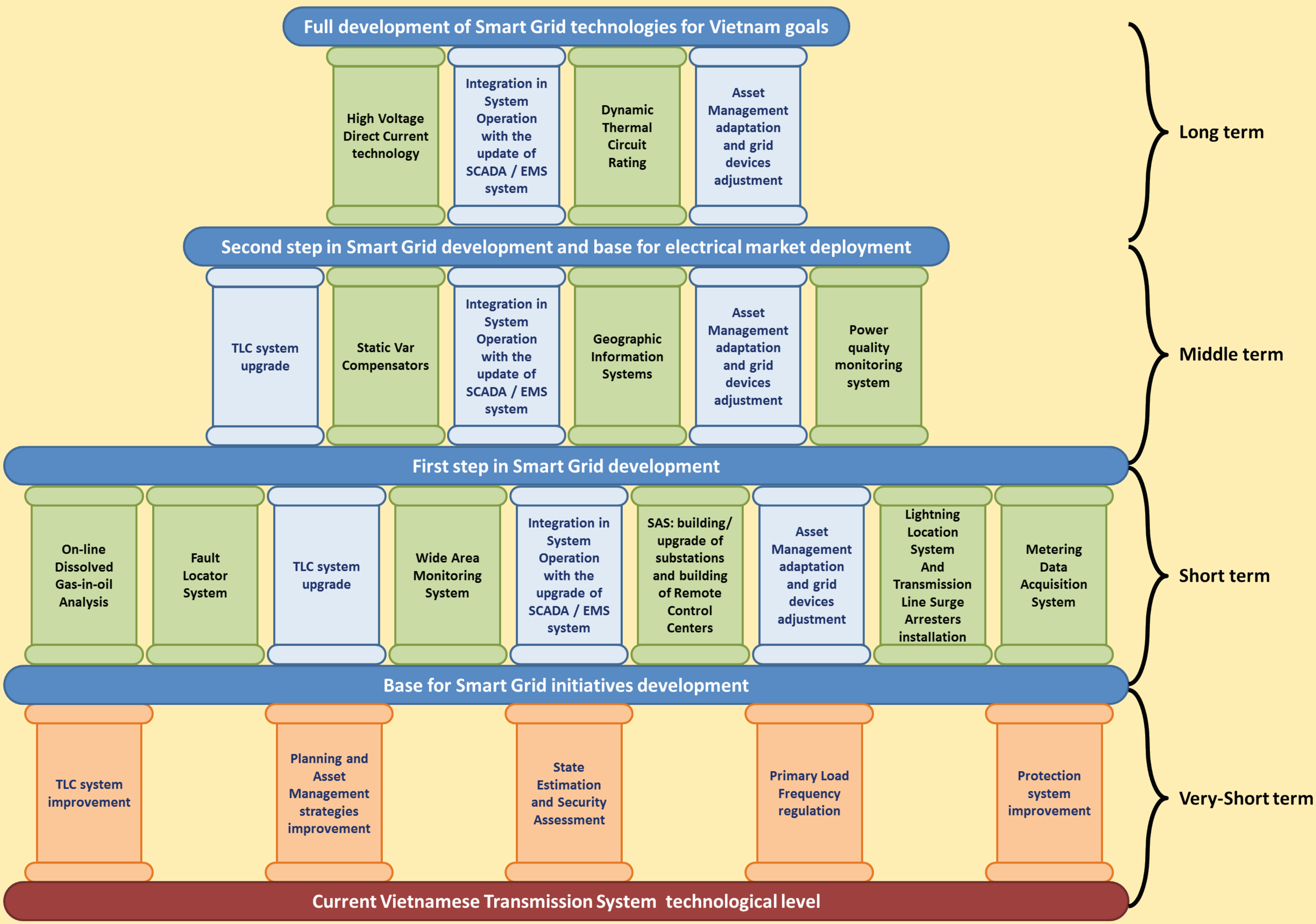
Long-term Smart Grid applications include:

a. **High Voltage Direct Current (HVDC) technology**. The technical and economic benefits that can be achieved are specific to niche applications, such as interconnections with neighboring countries or reinforcing the north-south backbone with high power flows or supplying large congested loading areas that have high levels of short circuit currents and loop-flow issues. However, this topic is not a priority and HVDC represents one of several solutions that are worth evaluating. The success of an HVDC link is measured by its load factor where a value above 0.7 can be considered satisfactory.

b. **Dynamic Thermal Circuit Rating (DTCR).** This document presents the main techniques used for implementing this Smart Grid solution. The steps required to develop a DTCR project that uses all the different techniques are also proposed. NPT has already planned the development of such an application, so the implementation of a pilot project will be a good starting point. On the other hand, it would be better to wait for the current rapid growth rate of the transmission network to stabilize in order to leverage this application on a large scale. According to international experience the dynamic ratings are typically 5% to 25% higher than conventional static ratings. The implementation of DLR will be considered satisfactory if on the lines where it is applied the "ampacity" increases from 5% to 25%.

Expanding on the concept of "pillars", the technical prioritization led to the refined Smart Grid roadmap (figure 5).

FIGURE 5: TECHNICAL PRIORITIZATION AND REFINED SMART GRID ROADMAP



Source: Authors

The technical approach used to prioritize the Smart Grid applications is a good starting point for the design of a phased roadmap, but it is not exhaustive. Further, some metrics for the evaluation of the success of the various Smart Grid solutions are proposed and summarized in the following Table 12.

The refined NPT Smart Grid roadmap will be finalized upon completion of the following: (i) application-specific cost-benefit and risk analyses; (ii) observations related to aspects of regulation, performance monitoring and implementation strategy. This work will be the focus of the next two reports accompanying this document.

TABLE 12: TECHNICAL METRICS IDENTIFIED FOR SMART GRID SOLUTIONS

SMART GRID SOLUTION	PERFORMANCE INDICATOR	SATISFACTORY THRESHOLD
Fault Locator System	Reduction of time taken to attend fault site by maintenance crew and related outage duration	25%
Wide Area Monitoring System	Voltage collapse prevention	15%-35%
	Out-of-steps prevention	15%-35%
Substation Automation System	Energy Not Served (ENS) reduction per year for each substation equipped with SAS	450 MWh
Lightning Location System	Percentage reduction of transient faults affecting the lines	20%-30%
Metering Data Acquisition System	Mean square error between the value acquired by the meters and the calculation by the settlement process for the same meters	0.4%-0.8%
Static Var Compensator	95% (1 σ) variation interval of voltage level of network "pilot nodes"	+/-5% of the rated voltage
	Voltage collapse prevention	15%-35%
Geographic Information Systems	Reduction of management costs	10%-15%
Power quality monitoring system	Percentage reduction of voltage dips	20%
High Voltage Direct Current technology	Load factor	0.7
On-line Dissolved Gasinoil Analysis	Reduction in the number of faults	80%
Dynamic Thermal Circuit Rating	"Ampacity" increase	5%-25%

Source: Authors

C. Introduction

C.1 General Overview

This document presents a technical analysis and develops key elements identified in the Inception Report in order to design the Smart Grid Roadmap for Vietnam. The general overview of the approach followed in this analysis is depicted in Figure 6 below.

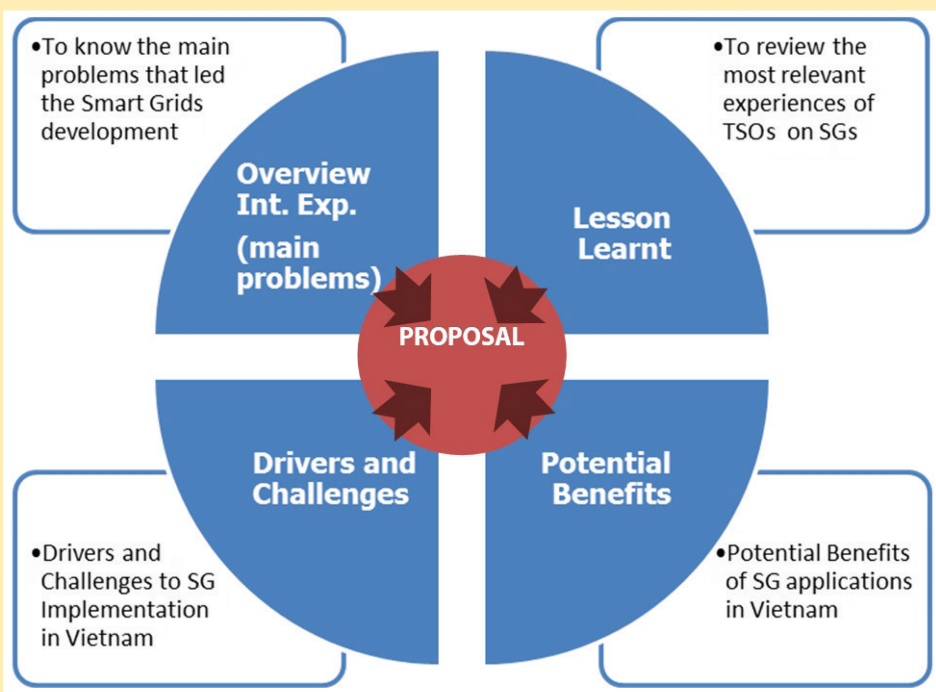
During the initial discovery process the issues and the challenges regarding the electrical network, together with all the information collected, were collated and studied in order to define the problems that needed analysis and investigation.

The vision of the proposed Roadmap, as presented in Figure 7, starts from these issues and identifies the possible Smart Grid Applications and Smart Grid devices that may help to resolve the identified problems.

The first objective of this document is to review international best practices that have helped to solve issues similar to the ones identified in the Vietnamese transmission network and, on this basis, to propose candidate Smart Grid Applications and/or technology in order to address such problems.

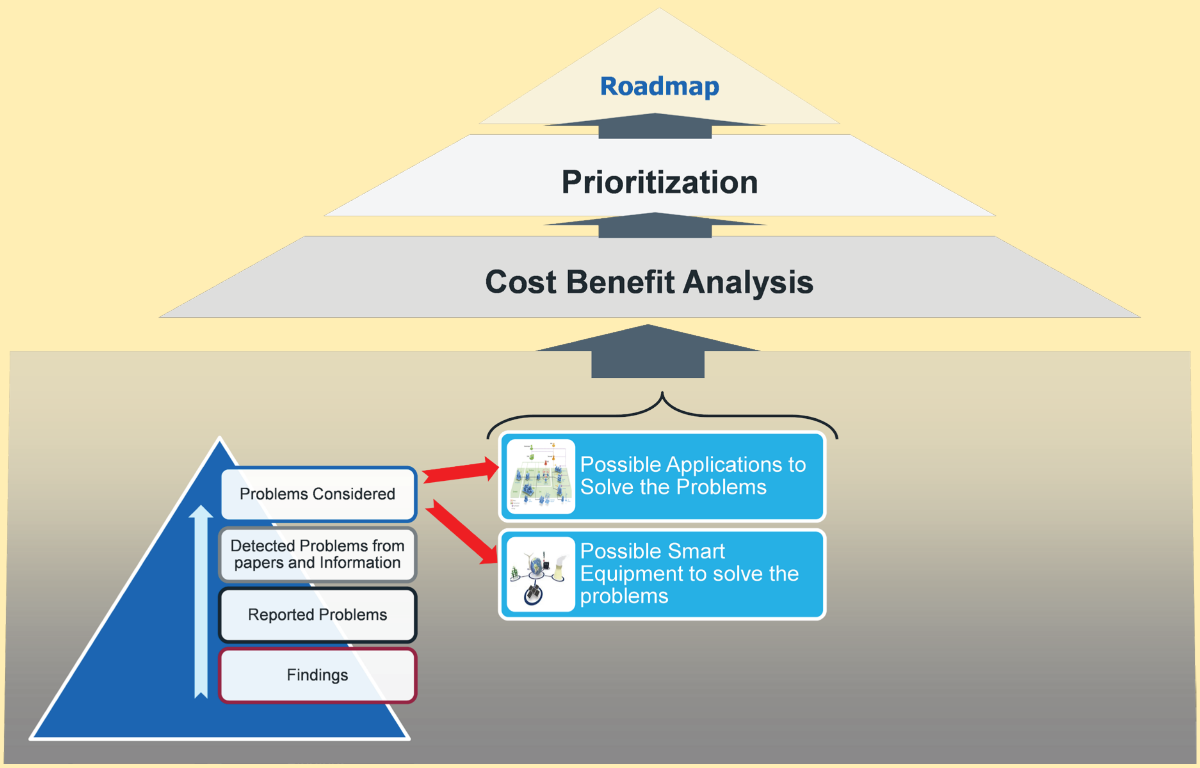
Smart Grid roadmaps articulated at an international level for mature networks may provide good benchmarks and useful examples in order to effectively plan the Smart Grid implementation for Vietnam while keeping in mind, as already stated, that this approach may need some refining. In this scenario the development of some applications and technologies will be considered as the fundamental basis for the subsequent implementation of more advanced applications.

FIGURE 6: GENERAL OVERVIEW OF THE APPROACH



Source: Authors

FIGURE 7: VISION OF THE ROADMAP



Source: Authors

For this reason the methodology for developing a Smart Grid roadmap will firstly define a number of essential concepts (e.g. state estimation, security assessment, remote control and regulation, asset monitoring and management) as the necessary "pillars" that will form the ideal foundation for the creation of a smart network.

The aim is to define a common shared vision of components and equipment for the Smart Grid development in Vietnam starting with the current operating model and the forecasted status of the electricity sector.

The Smart Grid initiatives must be tailored to fit the specific needs of Vietnam, taking account of not only the best practices and experiences, but also the current Vietnamese state-of-the-art Smart Grids projects as these will be the basis for developing an integrated roadmap specifically for Vietnam. This will be focused in the short-term on those initiatives that can be achieved quickly and consistently with the existing and approved on-going initiatives and, in the medium/long-term, on those initiatives that will require a longer development cycle.

C.2 Structure of the Document

This report is split into two main parts. The first part is composed of chapter 'D' while the second part is comprised of three sections ('E' to 'G').

The first part of this document (chapter 'D') addresses the identification of those international best practices and experiences of Smart Grid technologies that are applicable to the current Vietnamese situation and those that will help to develop their longer term roadmap.

For the introduction of the Smart Grid solutions in the Vietnamese context refer to 'Annex 1' and 'Annex 2 '. They respectively deal with:

a. The definition of best practices based on the experiences of electricity transmission system functions and owners from around the world. This view also defines the key players that have been involved and instrumental in the evolution of Smart Grid technologies to the present day.

b. A brief description of the current operating model of the Vietnamese electricity sector with a particular focus on the current challenges and issues faced by the Vietnamese electricity transmission operators.

The second part of this document ('E' to 'G') examines three specific aspects:

a. The identification of those Smart Grid solutions suitable and applicable to the Vietnamese context. The aim here is to map the Vietnamese issues and challenges to the proposed Smart Grid initiatives.

b. A detailed examination of the proposed solutions introduced in the preceding point above (46.a). The proposed solutions are a combination of technology (typically Smart Grid applications and infrastructures), processes, procedures and commensurate training. This section emphasizes the need to ensure that the pre-requisite infrastructure and training are both already in place to leverage the benefits of this combination of new technologies and processes.

c. A prioritization of technical and process developments to enable the integration of the Smart Grid technologies across the Vietnamese transmission systems, operators and functions. This prioritization is mindful of achieving the quick wins as promptly as possible whilst preparing the infrastructure and the operators for the short to medium term and the medium to long-term initiatives.

In addition to the approach outlined briefly above, the Consultant also aims to leverage his own experience and expertise to identify those areas of further development and opportunity that have not been identified yet by the Vietnamese operators, technicians and other experts that briefed the consultant during the discovery processes.

As part of this work the Consultant will also identify the means of measurement as well as the most relevant metrics to ensure the achievement of global policy targets such as e.g. the overall reduction of faults, short circuit events etc. across the electrical infrastructure as a whole. The parameters identified through the process of measurement will be tied to global policy targets (Key Performance Indicators) in the sector [1].

All of these steps will aim to delineate the vision and objectives of NPT's Smart Grid roadmap [2] and to define a technically driven phased implementation plan.

D. Relevant International Experiences of Smart Grids for Transmission Systems

D.1 Key Points Summary of International Experiences

This chapter is focused on presenting those examples of Smart Grid technologies from transmission utilities around the world that are most relevant for the Vietnamese network. These examples have been chosen on the basis of the applied design methods and for the types of problems they aimed to resolve as well as for the implemented solutions many of which are appropriate and relevant to the Vietnamese scenario.

The first international experience presented is that of Terna, the Italian TSO. The analysis of the Italian experience and subsequent initiatives is particularly relevant to the Vietnamese experience precisely because the long, thin shape of both countries has dictated a very similar north-south electricity distribution topology with a similar concentration of power plants at the extremities of the country.

The following sections discuss some basic applications and strategies exploited in the Italian transmission system in order to provide a useful starting point and context for the proposed solutions for Vietnam. For example, some parts of the Italian electricity network experienced short circuit levels that exceeded the rated current limit of the circuit breakers, however these problems were satisfactorily resolved by developing appropriate Planning and Asset Management tactics and strategies.

Further, as in Vietnam, the Italian network topology exposes the power system to transient and voltage stability problems. These issues, in the Italian network, were the key drivers for the development of projects like WAMS. The Italian WAMS experience may prove very useful for the positioning of Phasor Measurement Units (PMU) as well as for the kinds of applications developed and the process of progressive integration of WAMS functions in System Operations.

The Italian transmission network experience is also very instructive from the perspective of applications such as SAS, Lightning Location System, Power Quality Monitoring and Metering Data Acquisition System.

Moving from a single country, Italy, to the European electrical infrastructure sets the scene for elaborating a broader example of what constitutes appropriate planning for a large network. The European Commission's ENTSO–E Ten-Year Network Development Plan 2014 [3] brought together leading European TSOs in order to establish the guidelines for the development of the Europe-wide network. In particular, this plan focused on addressing transmission investments starting with the identification of bottlenecks across Europe. This process could become the basis of best practices in the future development of interconnections between Vietnam and its neighboring countries. Moreover, this experience highlights the importance of shared N-1 criterion assessment in a large interconnected system.

Another important European example of best practice is represented by Reactive Power Compensation in the UK, i.e. NGC (National Grid Company). This refers to the approach adopted by NGC, to ensure the control and regulation of reactive power exchange leading to the proper management of the voltage profiles in a transmission system. This was in the context of a significant change in the operation of the grid due to the substantial unbundling of the assets of the electrical system further compounded by substantial energy input from unpredictable renewable sources. The combination of these factors brought about the need for greater flexibility and a faster response capability in order to overcome the significant complexities of planning and programming the development of the transmission network on a medium/long term basis.

The third and final international experience that is analyzed below looks at some key Smart Grid initiatives implemented in the USA. Firstly, the USA experience with PMU installations and subsequent development of WAMS applications is very interesting because of their approach, the very high number of applications developed (confirming the potential of WAMS and in particular of the exploitation of PMU data) as well as for the results obtained.

The sophisticated technological level reached by the US transmission systems has resulted in the development of some very advanced Smart Grid applications like Dynamic Rating. Furthermore, thanks to the large number of ISOs and to their differing breadths of scope, there are lessons to be learned from very different responses to the same problems. Towards this end two dissimilar projects using Dynamic Rating are presented.

The USA transmission system experiences may encourage the introduction of online sensors to predict transformer failures (Dissolved Gas-in-oil Analysis - DGA). This technology is quite widespread but the majority of all the devices worldwide are actually present in the US networks (40,000 of the 80,000 worldwide). A particularly instructive incident at BC Hydro will be described in order to understand best practice of this Smart Grid solution. This may provide a good reference to evaluate the benefit of installing sensors for on-line DGA on new and old power transformers.

Another area where new solutions within a transmission network may be of relevance for the Vietnamese grid are those related to a new type of application developed for HVDC systems. Direct Current (DC) technology, in fact, has been used to resolve some problems similar to those experienced by the Vietnamese grid where the primary requirement was an increase in the level of transmitted power to large load areas. Towards this end the TRANS-BAY project for PG&E in California is discussed.

D.2 Italy

The primary relevance of the Italian experience to the situation in Vietnam is that prior to 2005 the structures of their Transmission Utilities were very similar. This is why it is important to highlight the structural composition, to underline the criticalities for the former and to describe the reasons for the evolution to the current Italian electricity transmission system organization.

The next few paragraphs present some aspects of the Italian experience for the following reasons:

a. To introduce best practice for the development of a Smart Grid;

b. To describe some useful Smart Grid initiatives.

D.2.1 Italian Transmission System Organizational Structure Experience

As a result of the "Decreto Bersani" Act in 1999 the former Italian ISO, ENEL, was unbundled and privatized. The unbundling process resulted in three new companies, viz: ENEL Distribuzione, owner and operator of the distribution network; ENEL Produzione, owner of the power plants; Terna, Transmission Owner (see Figure 73) below.

Since Terna was only a TO Utility, the role of operating the Grid was entrusted to a System Operator called GRTN ("Gestore della Rete di Trasmissione Nazionale"). GRTN was in charge of dispatching generation and operating the HV Grid.

The initial consequence of this split, in what had once been a single role now covered by GRTN and Terna, was the separation and demarcation between grid planning and operational functions. The first was the responsibility of Terna, which was the TO of the Italian network but not the System Operator. The latter was the responsibility of GRTN who had the experience and the ability to address system bottlenecks and implement the most effective remedies.

This dichotomy was apparent in the operational procedures. The agreement between the two entities stated that if a GRTN Control Room Operator needed to switch a line, they were required to ask Terna's Control Centers to open the circuit breakers.

This strict separation of roles between the two entities had some very serious implications. Every modification or enhancement to the grid (e.g. construction of a new line or installation of a key device) should have been driven by, or at least have taken into account, GRTN's recommendations on the most effective solution and the most ideal location of its application. In some cases the risk of grid planning strategies diverging from operational needs has been significant. This failing was becoming ever more apparent to the Italian government who had begun to reconsider the organizational structure of their electricity grid operators. It was against this background that the 2003 blackout gave this evolutionary process a greater impetus, because it highlighted how the Electrical Grid was, and will always remain, a vital strategic asset for any sovereign nation. Towards this end a more robust and controllable grid management policy was deemed necessary.

Thus, in 2005 GRTN and Terna merged together into a single company under the name of Terna S.p.A. The main driver for the change was political and aimed for compliance with the international experience of Transmission Utility organizational structures. In fact, in most countries where there was only one Owner of the network, the same agency was also the System Operator (single TSO instead of TO + SO).

In a country where the transmission utility has an organizational structure composed of a full-service TSO the role of an independent authority is fundamental to insure the operating transparency of the organization tasked with all the relevant functions and for simulating a competitive marketplace to ensure a fair, equitable and equal opportunity tariff system for consumers.

The Italian Authority for Electricity, Gas and Water is an independent entity tasked with ensuring competitive market pricing, cost efficient and balanced distribution of services across the country, ensuring equal access to all citizens, as well as enforcing adequate quality levels, through regulation and supervisory activities. The Authority acts as a consultant for the Italian Government providing recommendations or submitting proposals on future development of the Electrical, Gas and Water services. The Authority acts with complete autonomy and independence within the context of general political guidelines mandated by the Government and Parliament, and which are consistent with the regulatory framework of the European Union.

Among all the various functions addressed it is worth highlighting that the Authority:

a. Defines fees for the use of the various utility infrastructures;

b. Promotes, through its regulatory activities, the investments related to adequacy, efficiency and reliability of the services;

c. Ensures the openness and transparency of the service; and

d. Is in charge of monitoring, supervision and control in cooperation with other public supervisory bodies.

D.2.2 Planning and Asset Management

The short circuit level is one of the issues that involves more than one function of a transmission utility's organizational structure, in particular Planning, System Operation and Asset Management (grid constructor and maintainer). In fact, if the Planning function has to consider fault current level in projecting future devices installation (line, stations, etc.), it is without doubt that a good working relationship between Asset Management and System Operation functions, together with the ability to make tactical decisions, can provide prompt, timely and cost effective solutions to problems.

During the last few years the Italian transmission system dealt with high short circuit levels. In some portions of the network the fault current was tending to become too high for the rated current of the circuit breakers. During this period new substations were planned for areas where the short circuit level was much lower whilst the breakers for these substations were rated for much higher current levels than those parts of the network that were experiencing high short circuit levels.

The most critical devices in substations, from a mechanical point of view, are the breakers as in most cases busbars and bays are designed to withstand higher stresses. Even if this were not the case, small and cheap mechanical provisions applied to busbars and bays can easily enhance their resilience to dynamic stresses caused by short circuit currents.

Thus, Terna's planning function decided on a direct swap between the new substations and the existing ones by installing the old breakers of those substations experiencing high short circuit levels in the new substations and installing the new breakers in the old substations. The excellent working relationship between System Operation and Asset Management facilitated this swap, as it was well understood that the breakers from the old substations whilst older than the new ones, were more than capable of handling the short circuit current levels experienced in the new substation areas.

The cost of the operation was very low because no new devices were required and it only took a short time to effect the substitutions.

Furthermore, in order to solve some specific issues related to the short circuit currents exceeding the threshold of the equipment, Terna researched the installation of reactors between busbars (acting as a bus coupler) and specified all the associated equipment (the reactor itself, breakers, etc.). Such reactors can be equipped with a bypass breaker in order to switch it on or off depending on the dispatching condition of the system (i.e. short circuit power and load flow).

D.2.3 State Estimation and Security Assessment

The on-line State Estimation algorithm computes a complete description of the Grid operating point for every minute, with an external output every fifteen minutes. The State Estimation has two main features:

a. The topology processor; and

b. The Least Squares solver.

The topology processor checks the accuracy of the SCADA measurement for each busbar section of every substation. The main objective of the Topology Processor is to detect and correct any kind of inconsistency between powers levels, currents and all other floating values measurements and the opening state of the breakers (Boolean values). The congruency check is based on the power balance of the busbar section where the sum of all power flows and all power injections at the busbar should always be zero. When this power balance is not met the Topology processor changes the opening state of circuit breakers, or stops the power flows on certain line/transformer bays, to restore the busbar balance.

Once the Topology Processor has corrected all the topology/measurement mismatches in the substations, the Least Squares solver computes the power system snapshot using a weighted least squares algorithm. The solver minimizes the sum of the squared deviation between the estimated values and the measured ones, weighted proportionally for the inverse of the quality code of each measure.

The Security Assessment is automatically run every fifteen minutes, when a new State Estimation snapshot is available for third party applications within Terna's EMS. The Security Assessment is divided into two main tasks:

a. Steady State Security Assessment; and

b. Dynamic Security Assessment

The Steady State Security Assessment ensures that the system is fulfilling the N-1 security criterion. The contingency list applied in the assessment ranges from line / generation tripping, combined cycle power plant outage and Special Protection Schemes interventions. The N-1 security assessment is run on the most recent grid snapshot, coming from the State Estimation, and on a very short term forecast (next 15 minutes) of the grid. The very short term N-1 security assessment is a crucial part of a near realtime Security Constrained Generation Balancing, where an OPF algorithm dispatches the generating units to avoid overloading even for events covered by the N-1 contingency list.

The Dynamic Security Assessment ensures the grid's ability to overcome critical contingencies (e.g. N-k or North Border disconnection) that could lead to huge transient currents and electricity black outs should a planned countermeasure fail. The DSA procedure is automatically triggered after every output of the State Estimation and checks the systems dynamic behavior against a number of contingencies defined by Control Operators. Shift operators can configure and schedule in DSA whatever simulation they wish, from simple line tripping to busbar short circuit or Border disconnection and islanding from the ENTSO-E grid. The DSA procedure sources its data from the most recently updated models of generator controllers (prime movers, AVR, PSS, etc.) and of the Defense Plan (see paragraph 'D.2.4').

D.2.4 Defense Plan

The Italian Defense Plan is based on different countermeasures both automatically triggered and manually issued by Control Operators. The automatic defense actions are under frequency/under voltage load shedding, Special Protection Schemes acting on generation and controlled islanding of small portions of the power system. Manual defense actions range from the insertion of shunt compensation devices, shedding interruptible loads (called "Banco Manovra Interrompibili—BMI") and emergency load shedding (called "Banco Manovra Emergenza—BME") consoles.

If the Italian power system experiences a very severe transient current, with a strong imbalance between generation and power consumption, the frequency drop cannot be stopped by the primary load-frequency regulation or any other automatic countermeasure. To keep the frequency within a range where the system remains controllable by the Control Operators (that is to say with a frequency drop less than 5% of the nominal value) Terna has rolled out more than one thousand under frequency load shedding relays. The overall load shedding amount is about 60% of the power consumption of the entire Italian grid. Each under frequency relay is triggered by frequency thresholds, whose number may change according to the region where the device is installed, and are fed with both the frequency absolute value and its first derivative (rate of frequency drop). Terna also rolled out under voltage load shedding relays to counteract fast voltage drops due to unexpected load increase especially from reactive power greater than the primary voltage regulation capability or strong overloads on transmission lines. Under voltage relays are triggered by voltage thresholds and are usually deployed together with under frequency ones as one single device.

Some portions of the Italian grid have a physical structure that imposes limitations on power transfer, often referred to as "Critical Sections" or simply bottlenecks (see also paragraph 'D.3.1.4'). To avoid bottlenecks, counteract overloads on those transmission corridors and to prevent heavy re-synchronization transients Terna has designed a number of Special Protection Schemes. These SPSs are usually triggered by the trip of one, sometimes two or more, circuits of the bottleneck section and are generally designed to trip or reduce the power output of production power plants near the tripped circuit. The trigger comes from a very large range of often complex activation logics but most of them are driven by sensitivity coefficients. The SPS trips or reduces generations at power plants where greater reductions of the power flows on the remaining (untripped) circuits of the bottlenecks can be achieved.

The BMI and BME load shedding consoles are manually tripping actions of load and are available to Control Room Operators when no other automatic defense countermeasure would restore the safe operation of the power system. The BMI console allows Operators to trip special interruptible load, such as industrial environments where signed agreements exist allowing for such actions in case of emergency. This contract states the fee that Terna pays to this industrial consumer for the interruptible service offered. The BME is an extreme emergency load shedding console where operators can shed load from the whole power system in order to achieve a general reduction of power consumption.

D.2.5 Load-Frequency regulation

The Italian TSO, Terna, has a hierarchical Load-Frequency regulation, organized in three different control loops: (i) Primary; (ii) Secondary; and (iii) Tertiary Load-Frequency Regulations. Each loop acts on different time frames and serves different network objectives.

The Primary Regulation counteracts any generation-load imbalances due to contingencies and prevents the frequency drop increasing. The Italian Grid Code prescribes that every Production Unit with an "Efficient Power" of at least 10 MW will be party to the Primary Load-Frequency Regulation. The Code defines a Production Unit as any kind of generating unit, regardless of the energy source (e.g. Thermal, Hydro, CCPP or RES) connected to the grid. The Efficient Power is the power output (MW) that a Production Unit may deliver with no deviation for thermal energy sources, for a set number of hours for a Hydro power plant and in ISO condition for Gas turbines or combined cycle power plants.

To comply with the Primary Load-Frequency regulation each Production Unit must be confined to a suitable power margin between the working set point and the maximum (minimum) power output. That margin is called the Primary Regulation Reserve. The sum of all primary reserves of the entire grid is the Italian Power System Primary Reserve.

The Secondary Control restores the power exchange with the interconnected neighboring countries (France, Switzerland, Austria and Slovenia) at the scheduled set point. The secondary controller, fed by the frequency deviation Δf and the power exchange error ΔP, tunes the set point of the primary controllers, modifies the output power until the ACE is neglected. The power reserve allocated at each generating unit for secondary load-frequency control is referred to as the Secondary Regulation Reserve.

Unlike Primary and Secondary control, the Tertiary Load Frequency Regulation is a manual control process. As the Secondary Load-Frequency control increases the power output of each generating unit, the secondary power reserve is consumed. Control Room Operators may restore the secondary reserve by sending to generators, even if they are not participating in the Secondary Load-Frequency control, new dispatching provisions, e.g. switching on spare generating units or new set-points for operating ones.

D.2.6 Automation and Tele-Control for Substations

In 2006 Terna started a SAS project to substitute the old wired logic with a new hardware and software architecture that was consistent with the most relevant international standards.

In particular, IEC 61850 was assumed as a base reference for the allocation of functions and communications, whilst the communication with the remote center is performed using IEC 60870-5-101/104. This protocol selection is a shared best practice in a SAS project implementation.

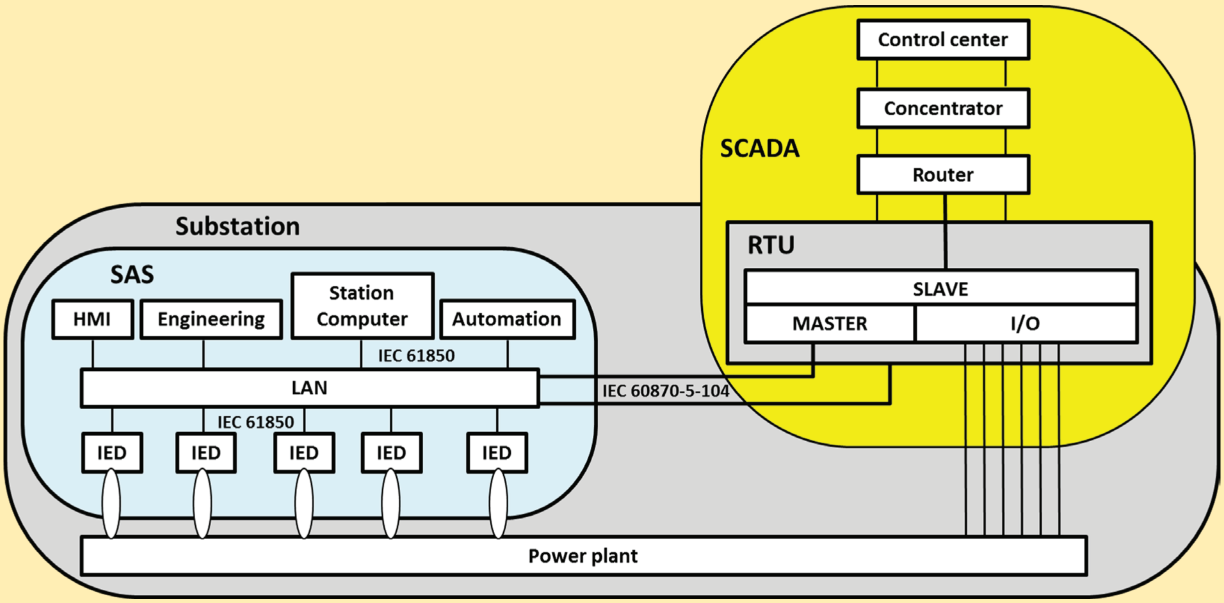
IEC 60870-5-104 is definitely preferable with respect to IEC 60870-5-101 as it is more flexible and easier to reconfigure when a system upgrade is needed. The existence of a significant number of old substations, which will require costly interventions to support IEC 60870-5-104, has led to the continued support of IEC 60870-5-101.

RTUs with a dual configuration which supports both IEC 60870-5-101 and IEC 60870-5-104 have been installed. In this way, when legacy substations are eventually upgraded to allow the use of IEC 60870-5-104 there will be no need to upgrade the RTUs.

Figure 8 shows the Italian SAS architecture, highlighting the basic systems and equipment involved; the two protocol used for communication are also indicated.

The implementation of the project requires the installation of a great number of new components, which can be affected by faults which also applies to previously installed equipment. In contrast to previous systems SAS provides not only the alarms but also the diagnostic information for all the components thus facilitating complete oversight and monitoring of all the equipment.

FIGURE 8: ITALIAN SAS ARCHITECTURE



Source: Authors

Thus, the main achievement of the SAS project development is not the reduction of system malfunctions but instead a substantial decrease in the time to locate faults and their causes thus reducing the mean time to repair. Consequently, outage times have been reduced leading to a significant decrease in the Energy Not Served (ENS) parameter, which is one of the key performance indicators (KPIs) in evaluating the success of any initiative deployment in a transmission system.

D.2.6.1 Lessons learnt

The Italian SAS experience is a useful illustration not so much for its architecture, which is fairly standard, but rather for the analysis of the constraints imposed on such a project in a mature transmission system characterized by consolidated infrastructure and strict regulatory systems.

This is especially pertinent to the development of the GOOSE initiative which was used for intra-substation communication, but not for information exchange between different substations. The existing telecommunication system, in fact, already connected all the substations with the control center and to avoid further cost IEC 60870-5-104 was selected as the communication protocol between substations that were star-wired from the control center.

This star-wired topology limited the full development of the SAS project and for the applications that might use this system as the topology meant that inter-substation traffic was obliged to pass through the control center thus reducing the speed and flexibility of system operation systems.

On the other hand, the existing regulatory system could create issues for future developments. One of the planned upgrades in Terna's SAS project is the monitoring of renewable/distributed generation. To achieve this Terna has to not only make further investments in telecommunication systems but also has to deal with regulatory issues regarding data exchange with the distribution network, where most of renewable/distributed generation is connected.

Some of these constraints are not present or could be avoided in a country like Vietnam, which is in need of a rapid expansion of the transmission system. In order to do this, all aspects of the project will need careful technical (interconnection between substations) and regulatory (monitoring of renewable generation) planning.

D.2.7 Wide Area Monitoring System

Following the severe blackout that occurred in Italy on 28th September 2003, the Italian System Operator (formerly GRTN, now Terna) undertook an action plan aimed at improving operational security by enhancing the monitoring facilities. The Wide Area Measurement System (WAMS) project, based on technology which offers emerging and highly functional solutions for power systems analysis, monitoring and control, commenced in 2005 and aimed to provide control room operators with new, advanced monitoring tools and facilities.

This was done under the banner of a Terna initiative called Plan for System Security, with the aim of revising and modernizing the network control procedures and analysis tools.

One major item of this plan was the design and commissioning of a wide area synchronized network [4], as shown in Figure 9, aimed at providing control room operators with advanced monitoring tools and automatic corrective controls, both phenomenon- and event-based, linked with a SPS [5]. The basic processing functions that were implemented included automatic alarms, on line frequency domain analysis, modal analysis and coherency areas monitoring.

D.2.7.1 PMU devices and their positioning strategies

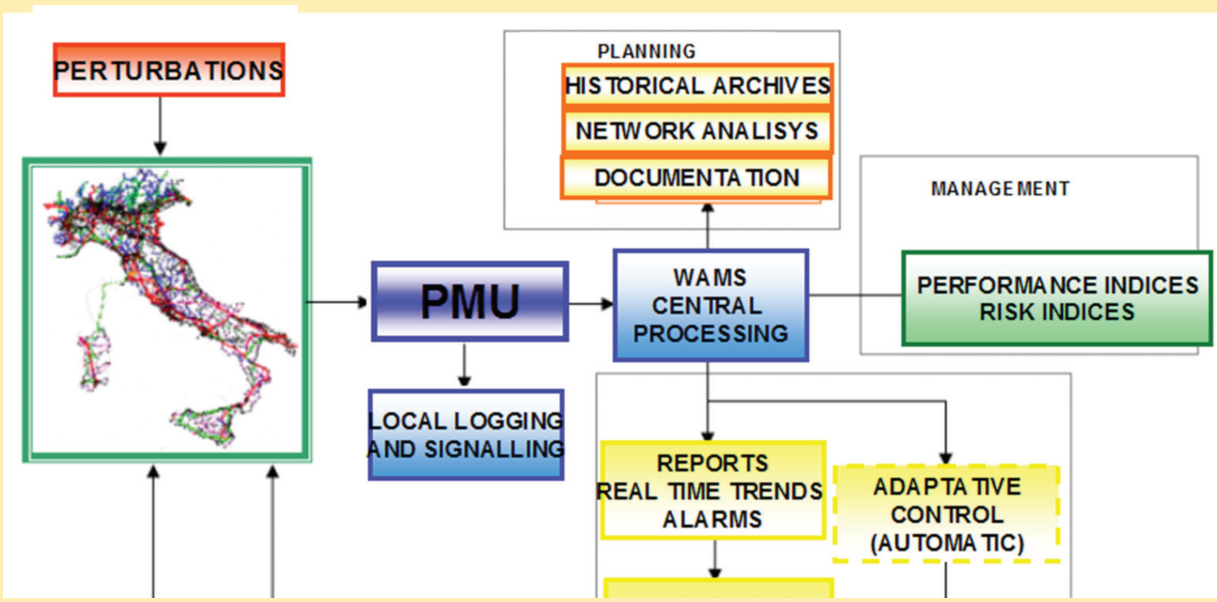
The first step of the Terna WAMS project was developed over a two year period and involved the installation of about 30 Phasor Measurement Units (PMUs) and a dedicated data network with monitoring applications for data processing as well as an intelligent display at the National Control Centre in Rome.

One of the critical aspects of the WAMS project was the location of the measurement devices or PMUs. As the number of PMUs necessary to assure complete system observability (e.g. for linear state estimation) would have been way too numerous, a limited number has been installed during the first rollout of the system. Device locations were selected to maximize the added value of the phasor measurements.

The optimal PMU positioning was considered from many different perspectives. In particular, based on the need to monitor critical portions of the power system, i.e. areas subject to specific types of events like line trips with possible cascading or voltage collapse, oscillations, etc., which could jeopardize system stability. The PMU positioning strategy was a two-step procedure combining heuristic and analytical criteria.

The first step was to apply a number of analytical positioning criteria separately, each one identifying substations worth equipping with a PMU. In particular, selection criteria focused on local and/or system-wide aspects regarding:

FIGURE 9: ARCHITECTURE OF THE WAMS APPLICATION AT TERNA (ITALY)



Source: Terna-CESI, 2008, (1)

a. Discrete event identification, such as line/generation tripping, by recording phasors were those events would cause the biggest step-changes of the network key variables (e.g. voltage magnitude);

b. Detection of electromechanical oscillations, by installing recording phasors close to generating units often affected by poorly dumped power swings;

c. Voltage stability monitoring, by installing recording phasors on busbars significantly affected by reactive power imbalances (e.g. those with high sensitivity); and

d. Angle and frequency stability monitoring, by installing recording phasors in areas often subject to grid islanding.

The operators' experience was invaluable for formulating heuristic based rules to select PMU locations e.g. proximity to large strategic generating units, bottlenecks, borders, etc.

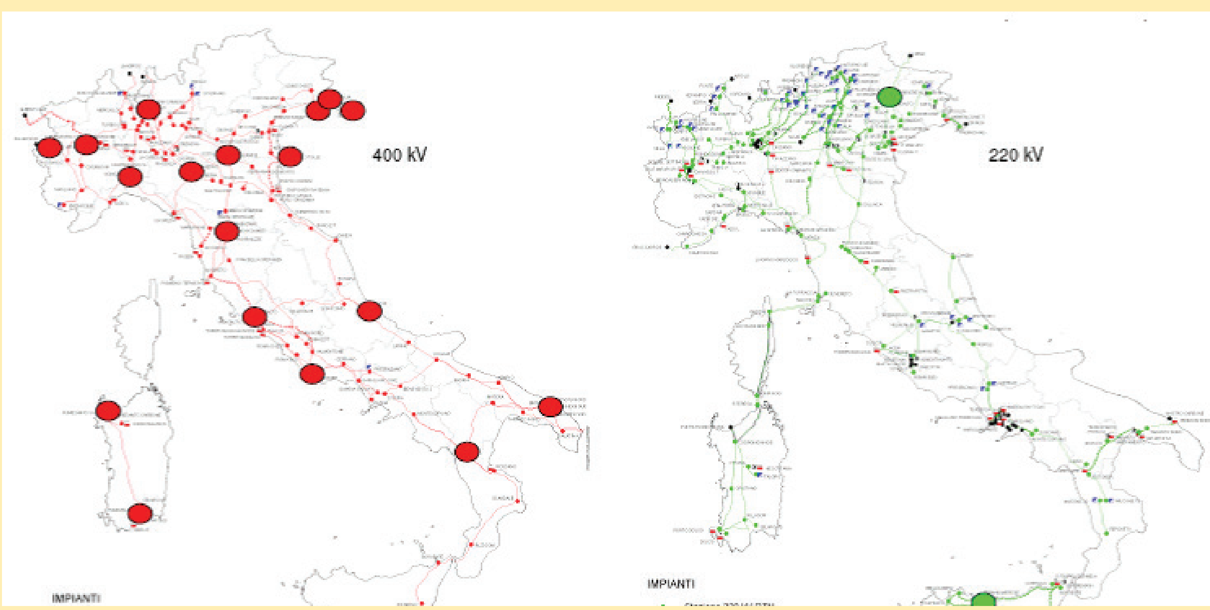
The second step was to identify the final PMU hosting sites. These locations were selected by combining all the sites selected by the different analytical criteria and those identified by operators' experience. The final PMU location list was the best compromise of all the listed sites. Figure 10 shows the deployment of the first 21 PMUs that were installed in the Italian HV grid.

Critical nodes were equipped with local recording and back-up functionality. In case of communication failure, the recording of significant transients is assured and the data can be retrieved at a later stage for postevent analysis. Recording is triggered by events (such as protection intervention) and by specific algorithms for detecting disturbances or by external manual activation.

The installed PMUs record phasor measurements at a rate of 50 samples per second (one every 20 ms). The PMU sampling window is between 20 and 50 ms wide, the processing lag is less than 10 ms. The measurement errors are within 0.1° for phase and within 0.01% for frequency. The data provided by the PMUs such as measurements, time stamps and the other status information is formatted according to a specific IEEE standard (originally 1344, then C37.118) and continuously transmitted to a central server by means of a high-reliability, high-performance redundant communication system comprised of dual data link channels.

The acquired data is stored in a real-time database, hosted in the RAM of the server machine with a redundant real-time back-up server. The monitoring application programs read the PMU data and write the results to

FIGURE 10: DEPLOYMENT OF THE FIRST 21 PMU DEVICES IN ITALIAN HV GRID (LEFT: 400 KV LAYOUT, RIGHT: 220 KV LAYOUT)



Source: Cigrè, 2007, (2)

a dedicated area of the database. The database is also accessed by the alarm management applications. The memory keeps the data of the last 30 minutes, aligned and chronologically sorted by time stamps. Older data is moved to a short term circular buffer containing 24 hours sampling at 20 ms, then to a long term archive hosting 30 days data sampled at a rate of one sample every 100 ms. Data can be permanently saved on operator request or if triggered by automatic disturbance detection.

D.2.7.2 WAMS functions and applications

After positioning the PMUs, a second very important aspect is the design of the monitoring application functions to provide useful information to system operators. First, an algorithm for event identification is tested under complete and incomplete observability conditions. In parallel the basic monitoring functions for operator support concerning voltage, angle and frequency stability are implemented.

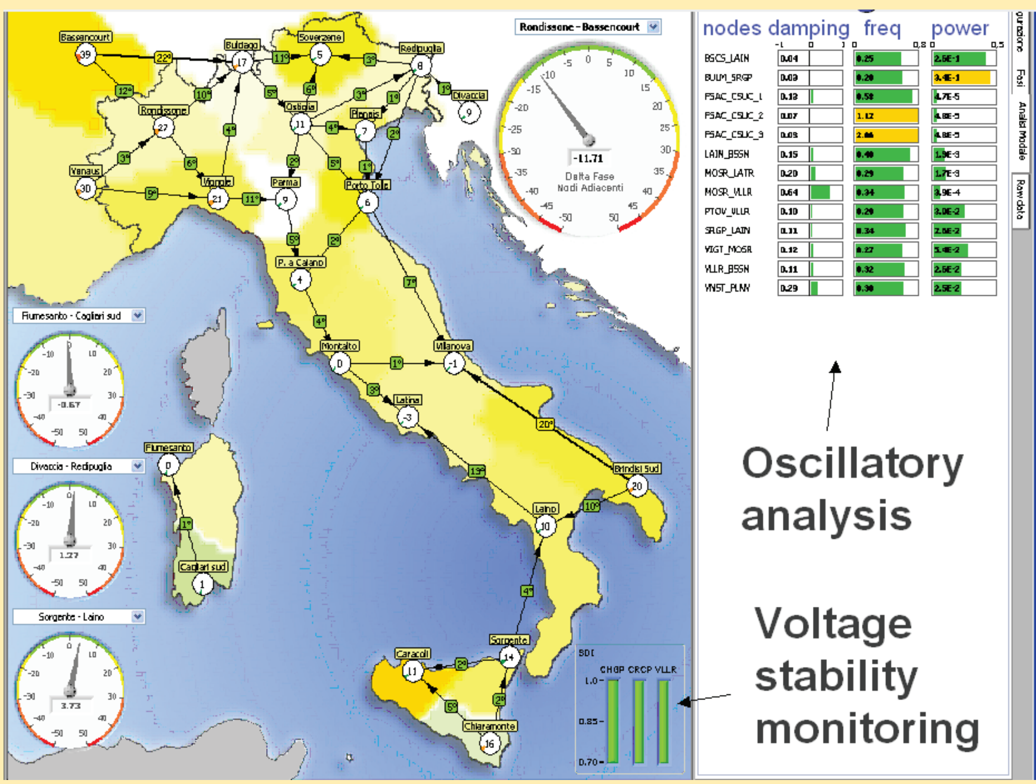
Displays and algorithms are available to closely track the voltage profile and stability margins and to give early warning of possible voltage collapse. Further, measuring the voltage angular difference between important line terminals or between generation and load areas is among the simplest and most effective indicators of system stress. It may also provide a guide for the reconnection activities.

Moreover, frequency is monitored to detect power imbalances and to perform an off-line disturbance analysis. Response and effectiveness of the frequency regulation and adequacy of the rotating reserve is tested. Figure 11 shows one of the applications developed at TERNA National Control Centre in Rome for basic on-line monitoring of the network using WAMS measurements.

Another major application expected from the wide area monitoring synchronized system consists of the modal analysis for real time and off-line identification of oscillatory behaviors. Knowledge of damping is a guide to the degree of stability of the operating conditions and helps identify unstable modes and contributory factors, [6] which directly suggest the countermeasures to be implemented.

The analyses conducted of the output of the first PMUs in operation on the Italian system confirmed the importance

FIGURE 11: APPLICATION THAT COLLECTS SOME BASIC ON-LINE MONITORING FEATURES



Source: Authors

of oscillation monitoring. For this purpose some digital signal processing algorithms have been tested and some off-line and/or on-line applications have been developed.

Among these tools one is of particular interest as its objective is to extract information from the recorded signals regarding the power system's electromechanical phenomena [7]. The data processing techniques are devoted to identifying both weakly damped oscillatory behaviors (mainly inter-area) and voltage instability (collapses), with particular attention to the time at which these dynamics took place and their trend.

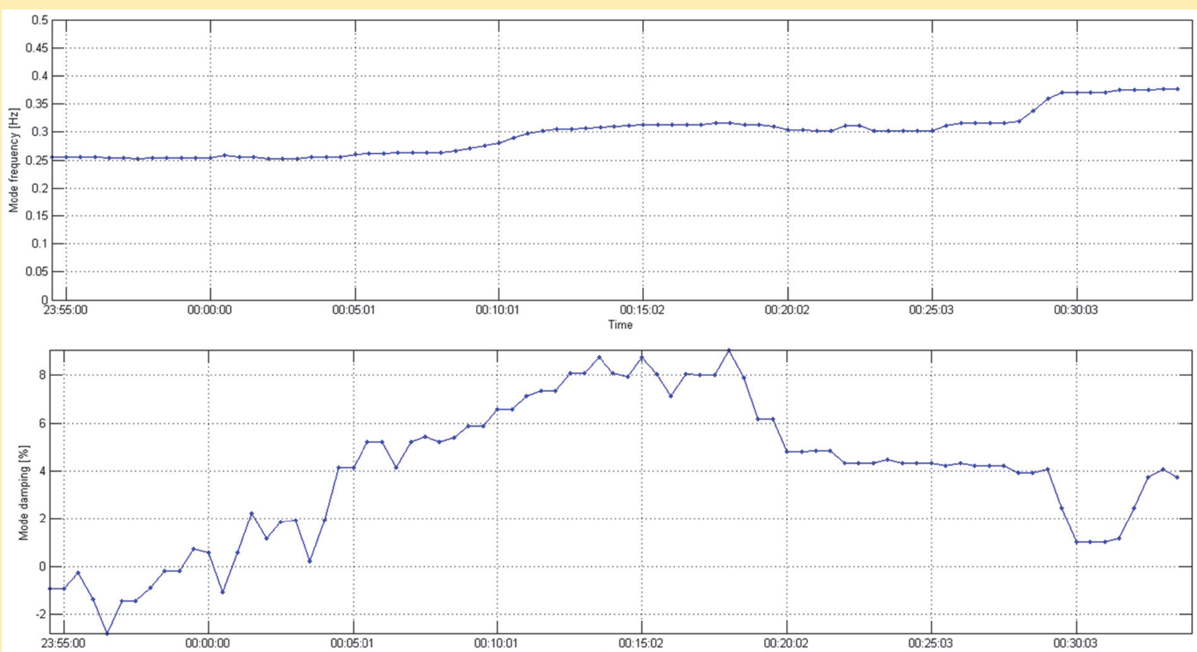
In this environment a number of algorithms are available, such as power spectral density evaluation, nonparametric methods (e.g. wavelet transform), parametric methods (Kalman filter, Prony and RLS methods), subspace methods, maximum likelihood estimation, S-Difference Indicator calculation (assesses voltage stability). An example of the results available from one of these methods of modal analysis is shown in Figure 12, which shows a frequency and damping estimation with model identification performed with a Kalman filter.

These techniques displayed a considerable potential to identify the frequency and start time of oscillatory behaviors in the signals and following a period of off-line testing have been implemented in an on-line application, currently in operation at the National Control Centre (Rome), which has made possible real-time monitoring of the network. On-line applications have collected a lot of analysis results obtained from long registrations (10-15 days) on which it is possible to conduct statistical analysis.

Analyzing distribution of frequency and damping is a very useful way of characterizing typical oscillatory modes crossing the different parts of the electrical network (Figure 13 shows an example). In fact, it is very important to investigate how their damping depends on time of day, load situation, network mesh conditions, amount of renewable production and the quantity of power exchanged with foreign countries. A particular focus is brought to bear on renewable production, whose behavior is generally less reliable than traditional power plants. It has been observed that in situations where there is a high percentage of renewable energy in the total production, the transmission network in less stable. So, if in such conditions a statistical analysis of WAMS data does not reveal any relevant decrease of damping in the typical inter-area modes, this may indicate the right environment for the integration of renewable generation.

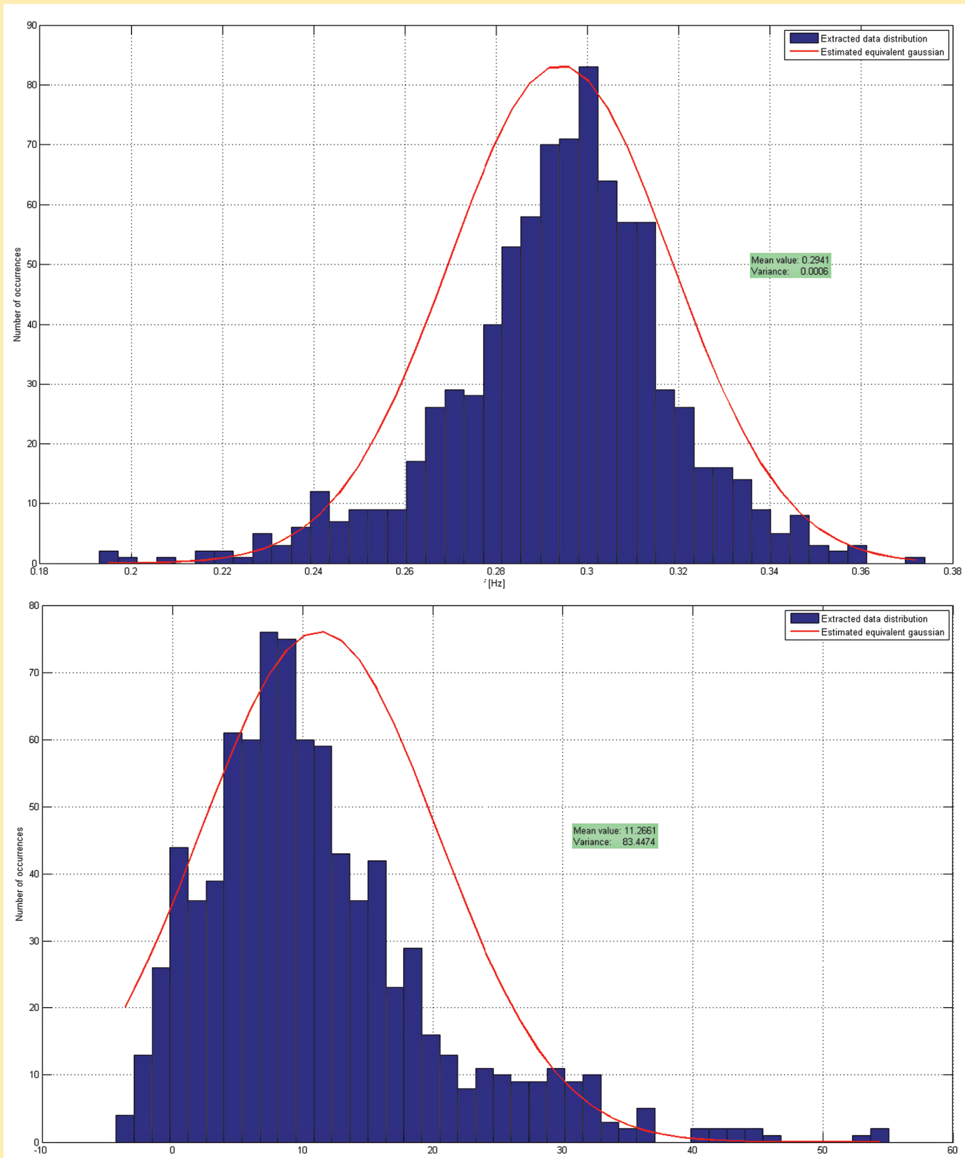
The WAMS project is on-going as is the installation of PMUs and at the time of this report the number of PMUs

FIGURE 12: FREQUENCY AND DAMPING ESTIMATION WITH MODEL IDENTIFICATION PERFORMED WITH KALMAN FILTER



Source: Terna-CESI, 2014, (3)

FIGURE 13: EXAMPLE OF FREQUENCY AND DAMPING DISTRIBUTION A DOMINANT OSCILLATORY MODE



Source: Terna-CESI, 2014, (3)

installed on the Italian network has reached in excess of 80 devices. The long term aim is to improve the observability of network dynamic behavior covering as much of the transmission network as possible.

Another important step in the development of WAMS in Italy was its interconnection with the complimentary systems of neighboring countries, for comprehensive control of the interconnected power network and in-depth monitoring of the power imported by the Italian system.

D.2.7.3 Project development and lessons learnt

Whilst the initial purpose of the WAMS project was to evaluate how effectively it can improve power system security further developments have been driven by the requirements for accelerated response and acceptance times expressed by the operators. One of the major issues that remain to be analyzed is the integration between WAMS and SCADA/EMS. In particular improving state estimation, event detection, frequency stability assessment, islanding detection and restoration tests support.

Furthermore, WAMS data has also been input to an algorithm for Dynamic Line Rating. This technique performs the estimation of the line's real-time temperature based on the identification of the electrical parameters of the line itself. These parameters may be calculated from the electrical characteristics (acquired from WAMS) of the line through an adequate electrical model [7].

This WAMS project will be a useful reference in F.5 because:

a. It was developed to deal with issues quite similar to the ones that occur in Vietnam;

b. The topic of PMU positioning was investigated in great detail (involving different TSO functions); and

c. It used a process of progressive integration of new applications as all of them were first tested off-line, then developed as on-line functions and finally their outputs were made available as additional features for the system operator (e.g. state estimation, restoration support, etc.).

D.2.8 Lightning Location Systems

In 'Annex 2b.v' the poor performance of exposed 220 kV lines during lightning strikes is identified as one of the most serious issues affecting the Vietnamese transmission network.

For transmission and distribution networks lightning events are a potential cause of damage, due as much to direct strikes on the overhead cables or towers as to indirect hits near power lines, which can induce over-voltages.

Further, over-voltages caused by nearby or direct lightning events may, in turn, result in phase-to-ground and phase-to-phase flashovers in power networks. This sequence of events produces voltage sags at customers' busses, which could give rise to serious malfunctions of a large number of devices and is a significant power quality limitation factor.

In electrical systems located in regions with high keraunic levels, lightning activity is responsible for more than 80% of the voltage sags that cause apparatus failures. Consequently, the correlation between relay operations and lightning events is of crucial interest for ensuring power quality improvement, especially in the presence of overhead lines. Indeed, appropriate insulation coordination and protection measures can be selected only after the assessment of such a correlation.

It is appropriate to discuss international experiences of such events to ensure best practice regarding implementation of the most appropriate countermeasures.

When maximum precision and accuracy are necessary in locating lightning prone areas, combined with the need to cover vast areas, they together provide a compelling argument to install a Lightning Location System (LLS) capable of high efficiency and the ability to precisely calculate single parameters. One of the best technologies in this field has been applied since 1994 by SIRF® to develop the Italian LLS.

The Italian LLS implementation was expressly commissioned by GRTN (now TERNA) and ENEL (the sole Italian power generation company in 1994), to keep track of lightning events and to acquire data on them in order to analyze their correlation with line faults and with protection behaviors.

The Italian LLS was implemented after a detailed analysis of the technologies available on the market and of the best sensor positions to cover the entire country with homogeneous and high performance devices.

Figure 14 is an sample of median lightning density ground mapping for the year 2000 and is typical of the output available from the Italian LLS system.

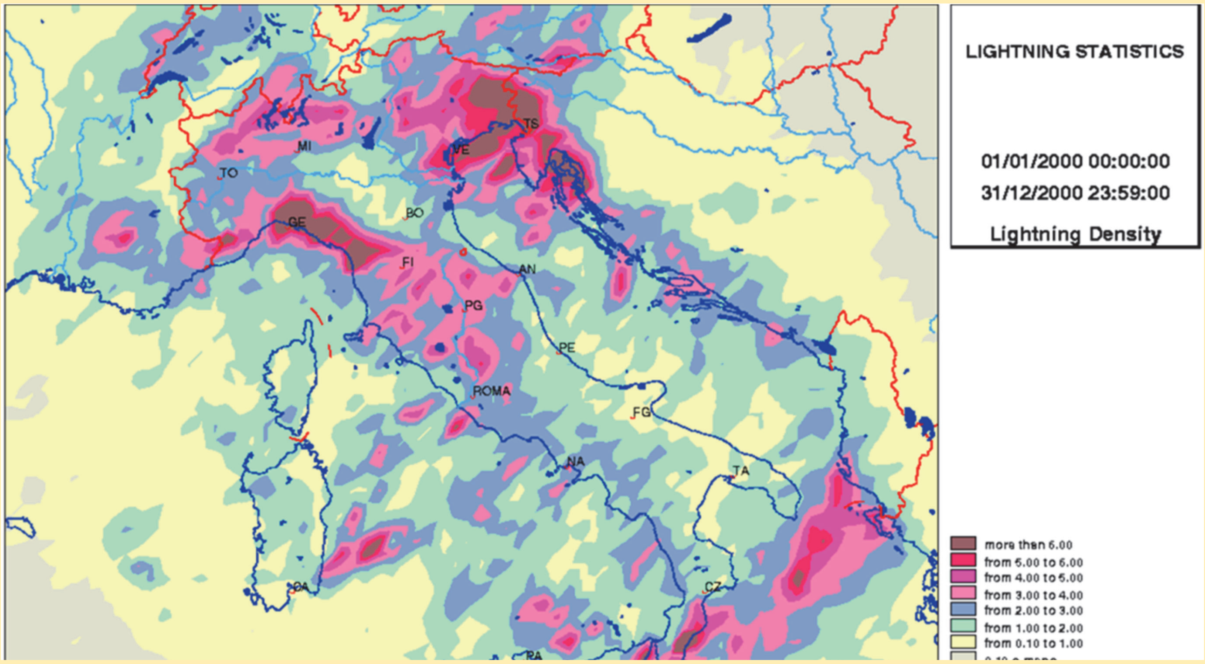
Such graphical representations are available thanks to the data acquired by the sensors installed all over the country; Figure 15 shows one of the Italian LLS sensors.

Since 1994, the Italian LLS has been one of the best performing applications in the world, with an uninterrupted, 24/7 detection performance. This system has a proven detection efficiency of more than 90% across the whole country, a mean location accuracy of less than 500 m and an ability to distinguish between cloud-to-ground and cloud-to-cloud events with greater than 85% accuracy.

Where electrical performances of power lines are involved, the ability to discriminate between cloud-to-ground and cloud-to-cloud are essential together with very good location accuracy for every single lightning to ground event.

All of this information provided by LLS is very useful for a Transmission System Operator. Terna in fact considers it a critical system and relies on real-time lightning information to dispatch energy, operate field personnel teams, study protection specifics and identify lightning-prone areas.

FIGURE 14: EXAMPLE OF A LIGHTNING STATISTICS MAP OF ITALY



Source: Authors

FIGURE 14: LIGHTNING DETECTOR

Source: Authors

Terna, both at the national control center and in the regional ones, performs realtime monitoring of lightning, 24/7, across Italy. Control room personnel use the real-time monitoring of lightning daily to verify the impact on power lines, to choose dispatching routes and to guarantee focus on the most urgent repairs. In particular, this application is very useful for system operation because knowing the location of lightning assists control room personnel to correlate network faults with lightning events in real time.

Furthermore, TERNA has applied the mean lightning density at ground data provided by the Italian LLS for the evaluation of line faults and assessment of the most exposed branches to be specifically protected with transmission surge line arresters. This parameter is always applied in the planning phase of a new transmission line route.

Finally, specific studies have been performed on those lines with abnormal fault behavior, correlating lightning and data on faults in order to find out where protection and/or transmission surge line arresters have failed or underperformed.

D.2.9 Power quality monitoring project

Power Quality (PQ) is a critical issue for transmission utilities which have among their many roles the duty to guarantee the quality of supply. Thus, PQ monitoring is an important service that these utilities must perform for both internal and regulatory purposes.

The types of disturbances to be monitored are well understood and are mostly due to:

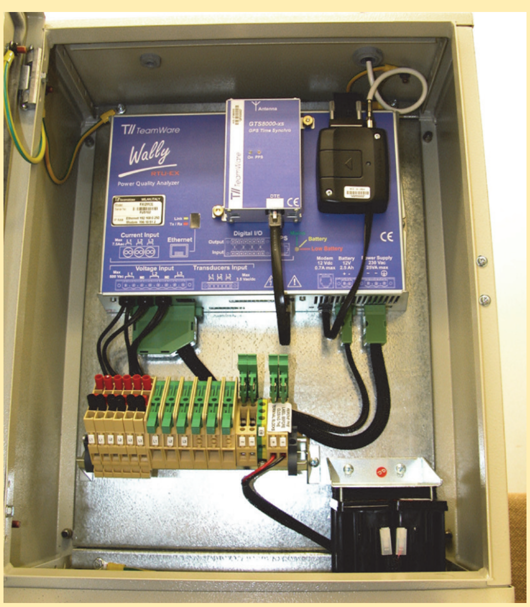
a. Network failures and faults on customer installations (voltage dips and interruptions for the consumers connected to the network);

b. Rotating machines and transformers inrush currents (rapid voltage changes); and

c. Rapidly changing loads and non-linear loads (Harmonics, dips and swells, flicker, etc.).

Furthermore, in the last few years, the spread of Distributed Generation units connected to the transmission network have been known to affect voltage regulation and provide abnormal voltage and frequency variations. Therefore, it is important for transmission utilities to know the real impact of these new installations in term of PQ delivered to the customers and distribution system operators.

FIGURE 16: SENSOR FOR POWER QUALITY MONITORING (WALLY)



Source: Authors

Today, the technology is highly effective and can identify problematic conditions. So, a modern PQ monitoring system should contain the analysis tools needed to organize and study the collected data.

Italy approved a plan for the detection of voltage quality on the national transmission network in September 2005 for which Terna developed a PQ monitoring system.

In order to acquire data to perform PQ monitoring Terna installed about 200 sensors to cover the most significant points all over the transmission network; Figure 16 shows one of the devices used.

All the acquired data is synchronized by GPS and collected in a central elaboration system with the purpose of determining the statistical averages of the main types of disturbances and understanding both the way in which these are propagated across the network and the possible correlations with the causes that can generate them.

Terna, on the basis of the results of measurement programs, has defined the expected levels of voltage quality, relative to:

a. The maximum annual number of transitional interruptions per-user;

b. The maximum value of voltage dips for each user;

c. The maximum level of total harmonic distortion;

d. The maximum value of the degree of asymmetry of three-phase voltage; and

e. The maximum value of voltage fluctuation severity indices in the short and long term.

By analyzing the data acquired and comparing it with the listed thresholds it is possible to evaluate PQ in the different parts of the network, to localize problems and to plan actions to address them.

In particular, it is possible to identify the probable components that can cause problems and use that information to direct intervention strategies even when Terna does not own these devices. The Italian TSO in fact has the prerogative to request maintenance and/or replacement of equipment that causes or has been known to cause problems on the transmission grid, especially if they violate the PQ standards.

Furthermore, Terna considers PQ monitoring system very useful for assessing protection system performance as the data collected can be exploited to identify anomalous protection behaviors. Analysis performed has revealed that in a normal situation most of voltage dips (over 80%)

have a typical duration of 20 and 200 ms (see Figure 17); such duration is compatible with the closing speed of the switches for the intervention of the distance protection measures configured as the 1st step. There is a fair percentage (10%) of holes which lasts up to 500 ms which correspond, in all probability, to the intervention of the distance protection measures in the 2nd step.

If the analysis of PQ monitoring data shows an abnormal distribution of the events, characterized by an excessive concentration of voltage dips corresponding to the 2nd step of the distance protection measures, this reveals the presence of malfunctioning or incorrect settings in the protection system.

D.2.10 Metering Data Acquisition System

Measurement in the electricity sector is carried out for different purposes, the most important of these are the following:

a. Measuring the power in real-time (e.g. every 4 seconds) for remote monitoring systems;

b. Measurement of the electricity used for billing and accounting purposes (to calculate the due amounts); and

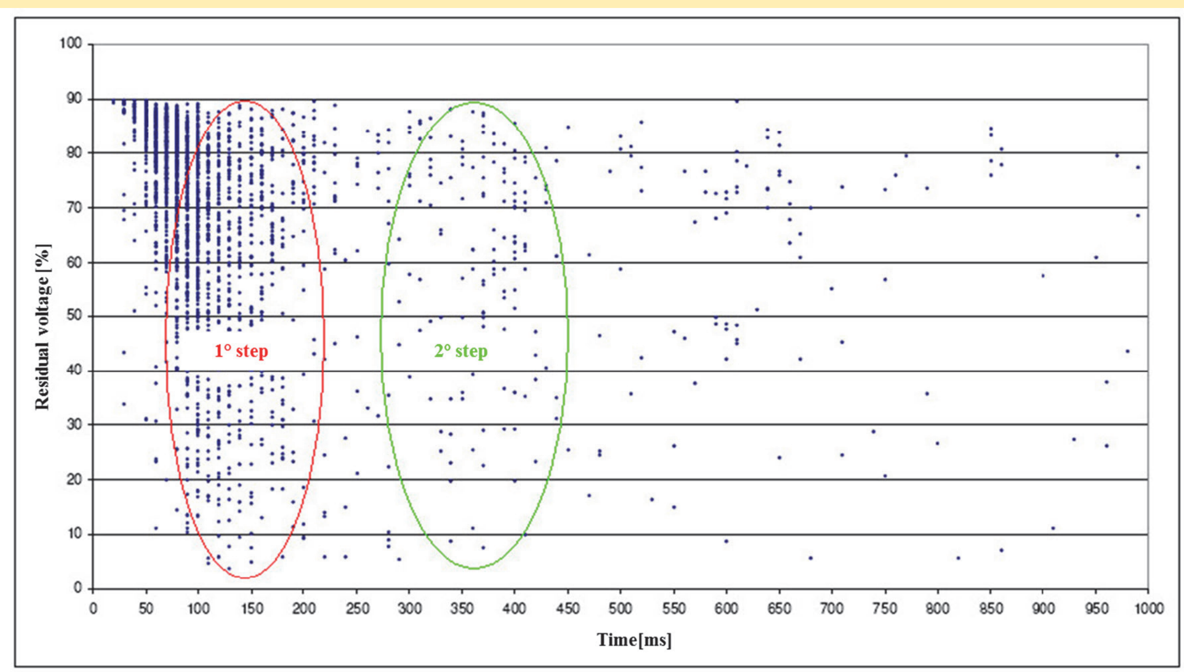
c. Measurement of electricity injected and/or taken from power units or withdrawal units, at those points of connection to the network for third parties, and used for commercial purposes (for example in the Electricity Market).

The main task of Metering is to acquire, develop and validate measures of energy used for commercial purposes by Settlement systems (activities aimed at identifying the amount of energy injected and/or taken from the network by each electrical operator) and by billing systems. So, a Metering System is mainly engaged in the exploitation of the third type of measurement (i.e. 159.c above).

The concept of metering as it applies to a transmission network is directly connected to one of the functions of a full-service TSO, like Terna, which has to ensure the transmission of electricity from the entry points (power plants, import from interconnection lines with foreign countries) to the withdrawal points (factories, substations, utilities, auxiliary services, etc.).

Thus, Terna's experience of Metering Data Acquisition Systems on the transmission network may be very useful in particular because the Italian TSO recently upgraded its system, under the project name MeTer at the end of 2011. It will be helpful to identify the guidelines of the

FIGURE 17: CORRELATION BETWEEN THE NUMBER OF VOLTAGE DIPS AND PROTECTION BEHAVIOR



Source: Authors

project and the number of devices involved and to highlight its main challenges.

Project MeTer's main business goals and technology were:

a. To increase its level of efficiency and effectiveness;

b. To increase productivity, by improving the level of interactivity and of response times;

c. To improve performance level;

d. To improve the security policies; and

e. To improve scalability, in terms of functional processes to manage.

The total number of installed meters in December 2010 was 7,102, allocated as follows:

a. Generation = 2,208 (31.09%);

b. Links to foreign countries = 56 (0.79%); and

c. Withdrawals = 4,838 (68.12%).

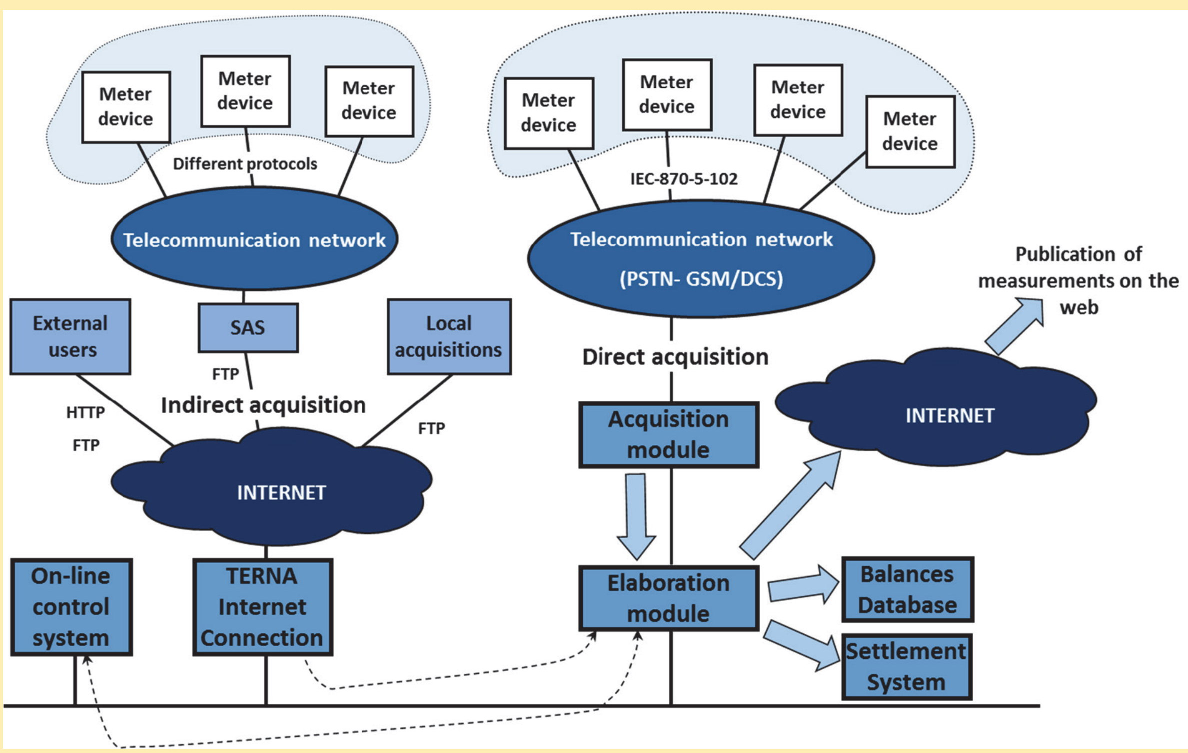
Some (4,800) of these meters have been installed in indirect mode acquisition using SAS. There is a strong connection between these two kinds of Smart Grid projects (Metering Data Acquisition System and SAS), which are significant for the Vietnamese transmission network where both the initiatives are being developed or are in the process of being implemented.

To highlight the two different types of acquisition (direct and indirect) and to show the interconnection between the different systems and devices involved, the schematic below shows the structure of Terna's Metering Data Acquisition System (Figure 18).

In developing this kind of project Terna had to manage regulatory issues, especially regarding data-exchange with distributors. Under the terms of the current legislation, Terna is responsible only for the detection of the energy transmitted from power plants on national transmission networks, while the distribution companies are responsible for the detection (as well as the installation of meters) of all energy transit on their networks (entered and withdrawn).

In order to control the electricity flowing through the network and in order to be able to acquire the metering data communicated by distributors, Terna in 2006–2007

FIGURE 18: TERNA METERING DATA ACQUISITION SYSTEM STRUCTURE



Source: Authors

signed specific agreements with the various distribution companies directly connected to the national transmission network. Such agreements allow Terna to extend its metering system and acquire metering data directly, however measuring relevant energy entries and energy withdrawn from the network is the responsibility of distributors.

Although the signing of the agreements has created the conditions for a regulated discussion on measuring the energy withdrawn, which was, prior to this agreement, impossible to achieve, some difficulties remain. There are some issues regarding the location and registry of the plants and the lack of leverage with distributors.

In order to address this aspect, in April 2011, Terna asked the electrical authority to intervene by authorizing Terna to apply commercial market rates for energy flows transiting its network and to reduce the number of repeated and late adjustments of withdrawals from the network.

Moreover, in implementing the MeTer project, Terna dealt with two key technical points:

a. The correct identification of that portion of the network (with the obligation to connect third parties) to which the power plant is connected as it is very important to identify responsibility for the collection, validation and recording of electrical data.

b. The correct identification of the voltage level on that part of the network to which the power plant is connected as this is fundamental both from a commercial point of view and for balancing the power levels of the network.

An analysis of Terna's experience highlights the main activities of a metering process from the technical point of view as given below.

a. Acquisition of the measurements from the field through a direct acquisition model;

b. Recovery/reconstruction of missing data and correcting transmission errors; and

c. Processing and aggregation of measurements.

Furthermore, the generation side demands:

a. Qualitative analysis of the measurements through comparison with the data acquired by Terna's system (Remote Control, Programs, Limits);

b. Validation and publication of aggregated input and withdrawals from single power plants;

c. Management of any claims received by the electrical operators; and

d. Power plant inspections.

The generation side is more relevant from the electrical market point of view as measurability is the basic criterion for the admission of a power plant to the electrical market. The measurability of a power plant is verified when the measurement devices installed are such as to allow, using appropriate algorithms, the measurement of the net electrical energy traded by the power plant from the point of entry to the power grid to which it is connected.

D.3 Europe

Paragraph 'D.1' presented the European as an example of best practice for the following reasons:

a. The European Commission's ENTSO –E Ten-Year Network Development Plan 2014 [3] as best practice in the future development of interconnections between Vietnam and its neighboring countries. Moreover, this plan highlights the importance of shared N-1 criterion assessment in a large interconnected system.

b. The Reactive Power Compensation in the UK, adopted by NGC, to ensure the control and regulation of reactive power exchange and therefore the proper management of the voltage profiles in a transmission system.

D.3.1 ENTSO–E European Ten-Year Network Development Plan

D.3.1.1 Background

The original purpose of the European interconnected transmission infrastructure was to provide an essential backbone to ensure the security of supply in continental Europe. The system has been evolving over the last 50 years with a view to assuring mutual assistance between national subsystems. However, there has been a fundamental paradigm shift over the past decade or two. The European transmission infrastructure is no longer just a tool for mutual assistance but has become the platform for shifting ever increasing power volumes across the continent.

Market development has resulted in higher cross-border exchanges with short-term commercial objectives. Other cross-continental power flows result from the rapid and successful deployment of regional intermittent energy generation with low predictability (e.g.: wind power). These developments were not taken into account in the original system design.

Furthermore, due to environmental reasons, the development of the transmission system is increasingly affected by stricter constraints and limitations in terms of licensing procedures and construction times. Many UCTE TSOs are facing significant difficulties with building new overhead lines due to long authorization procedures and regulatory regimes.

D.3.1.2 2006 European areas separation

This situation led TSOs to operate the system closer and closer to its limits as defined by current security criteria based on the physics of the system. This, therefore, will remain of decisive relevance for the secure operation of the electricity transmission infrastructure.

On November 4, 2006, there were significant East-West power flows as a result of international power trades and the obligatory exchange of wind power feed-in within Germany. In this situation the 380 kV double circuit line Conneforde-Diele in Germany was switched-off and the E.ON Netz grid was not in a "N-1" secure configuration.

Following this disconnection the resulting power flows on other lines in the 380 kV Landesbergen (E.ON-Netz)-Wehrendorf (RWE TSO) network were so close to the thresholds of the protection system that even a relatively small power flow deviation could start line trips cascading across the Europe-wide network.

Between 22:00 and 22:10 (4 Nov, 2006) [8], as the power flow on the Landesbergen-Wehrendorf line increased, it triggered a line trip that cascaded across a number of other networks thus proving the point about the importance of the N-1 criterion. The tripping of several high-voltage lines split the UCTE grid into three separate areas (West, North-East and South-East as shown in Figure 19 below) with significant power imbalances in each area. In the Western area this power imbalance induced a severe frequency drop that caused an interruption of electricity supply to more than 15 million European households.

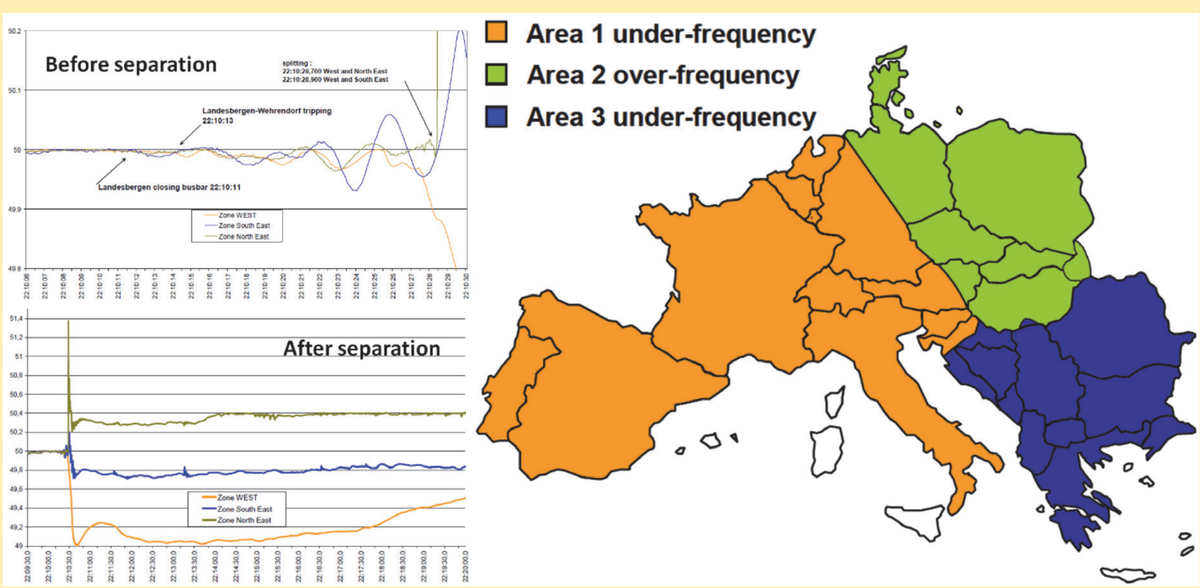
As a response to this crisis the automated countermeasures in each individual TSO responded quickly avoiding further deterioration of the systemic conditions. Within 38 minutes of the network splitting as a result of the cascade tripping, the TSOs were able to recover the full resynchronization of the UCTE system and then to re-establish a steady-state situation in all European countries in less than 2 hours.

D.3.1.3 Situation awareness and remedial actions

This incident focused UCTE's attention on two main issues:

a. N-1 criterion assessment; and
b. Inter-TSO coordination.

FIGURE 19: FREQUENCY TRENDS AND AREA SEPARATION



Source: UCTE, 2006, (4)

The N-1 criterion is a basic operating principle within UCTE and is critical to prevent disruptions from spreading. This rule requires that any single loss of transmission or generation element should not jeopardize the secure operation of the interconnected network, that is, trigger a cascade of lines tripping or the loss of a significant amount of consumption. Recommendation 1 [3] requires the TSOs to review the application of the N-1 criterion in terms of:

a. Defining the relevant parts and specific conditions in the adjacent systems which have to be taken into account in the TSOs security analyses;

b. Simulating the contingencies (tripping of power system elements) located outside the TSOs own control area;

c. Mandatory and regular online contingency analysis (N-1 simulations) connected to the alarm processing system; and

d. Preparation and regular checking of the efficiency of remedial actions through computer simulations.

The prompt and successful application of the proper countermeasures within a few minutes of an incident demonstrates the efficiency of the decentralized responsibilities of TSOs. In any case Inter-TSO coordination is crucial for maintaining the security of the system. This co-ordination has to be exercised over different time scales, from long term planning to real time operation. In order to achieve this aim the development of standard criteria for coordination between regional and interregional TSOs is necessary. So, UCTE Recommendation 4 [3] was drafted with the purpose of setting up an information platform allowing TSOs to observe in real-time the actual state of the whole UCTE system, in order to react in a prompt and timely manner during significant power disruptions.

The European Ten-Year Network Development Plan has been developed over an extended period and Europe's new electricity paradigm is driven by three main factors:

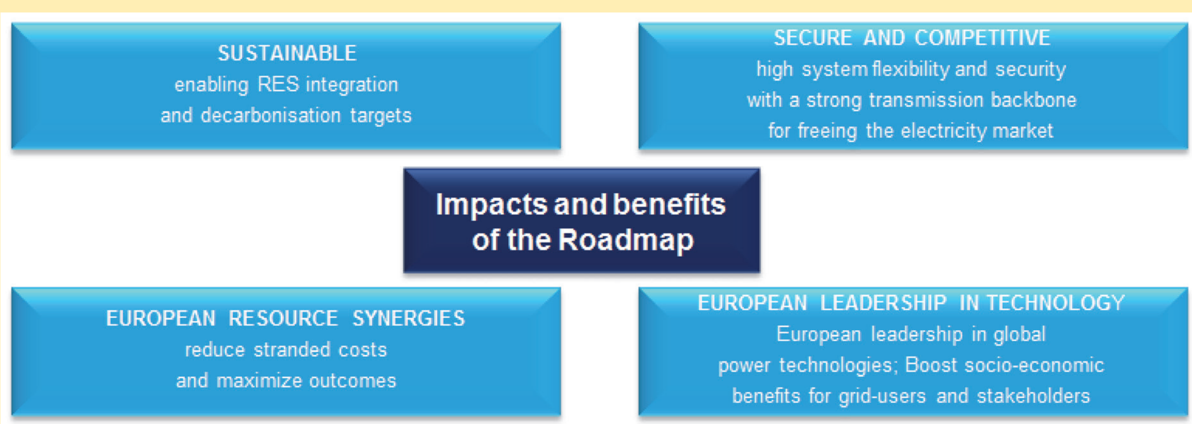
a. EU energy policy deriving from the EU's "20-20-20" objectives and the recently adopted EU Energy Roadmap 2050;

b. The IEM, which is to be completed by the target date of 2014 as defined by the EU Council in February 2012; and

c. The deployment and implementation of the Smart Grid.

These principles will make the European energy market completely reliant upon its strong transmission backbone while continuing to maintain security of supply and liberating the electricity market. The Smart Grid roadmap, whose impacts and benefits are emphasized in Figure 20, will allow the European manufacturers and ICT providers to develop innovations and bring them to market. Furthermore, the cooperation with research partners will create new opportunities and allow ENTSOE to further refine this roadmap in the coming years creating synergies that can be exploited in Europe to reduce costs and maximize results.

FIGURE 20: IMPACTS AND BENEFITS OF SMART GRID ROADMAP



Source: Authors

D.3.1.4 Identifying Bottlenecks and Transmission investment needs

The strategy for the definition of the needs of the transmission network deserves particular focus. A market and network study has been performed and, as a result, about 100 bottlenecks have been identified (shown in Figure 21).

The bottlenecks occur in those grid sections where the transfer capabilities may not be large enough to accommodate the likely power flows that will need to cross them and in the coming decade new transmission assets will be required in order to ameliorate these bottlenecks. The likely bottlenecks have been listed according to three types of concern:

a. **Security of supply:** When some specific areas may not be supplied according to expected quality standards and no other issue is at stake;

b. **Direct connection of generation:** Both thermal and renewable facilities; and

c. **Market integration:** If inter-area balancing is at stake a distinction needs to be made between that which is internal to a price zone and that which is between price zones (cross-border).

The analysis of the bottlenecks highlights that the most critical area of concern is the stronger market integration within mainland Europe of the four main "electric peninsulas" in Europe, highlighted in Figure 22.

These are all large systems (50-70 GW peak load) supplying densely populated areas with high RES development prospects, and as such, they require much greater interconnection capacity to enable the development of wind and solar generation. To this end, interconnection capacities should double on average by 2030. Investment needs are likely to trigger extra-high voltage grid investments in order to restore the grid's ability to fulfill the duties and services expected from the infrastructure**.**

FIGURE 21: MAP OF MAIN BOTTLENECKS IN THE ENTSO-E PERIMETER

Source: ENTSO-E, 2014, (5)

FIGURE 22: THE FOUR MAIN "ELECTRIC PENINSULAS" IN EUROPE

Source: ENTSO-E, 2014, (5)

D.3.1.5 ENTSO-E Committees targets

Finally, the ENTSO-E committees have utilized both bottom-up and top-down design approaches to define six roadmap targets for 2050 as follows:

a. To facilitate development of a pan-European grid architecture that fulfills the lowcarbon requirements of the Energy roadmap for 2050 and enables effective power delivery throughout Europe;

b. To demonstrate, understand and appraise the impact and potential benefits of state-of-the-art power technologies and offshore solutions;

c. To design and validate novel ICT-based methodologies for network operation that meet the reliability targets of both today and tomorrow;

d. To develop the market designs for the IEM that is most beneficial for system operators, market participants and consumers;

e. To determine and develop an optimal asset management strategy for equipment on a cost-effectiveness basis; and

f. To strengthen collaborations between TSOs and DSOs in their efforts to integrate distributed energy resources.

D.3.2 Reactive power Compensation in UK – NGC experience

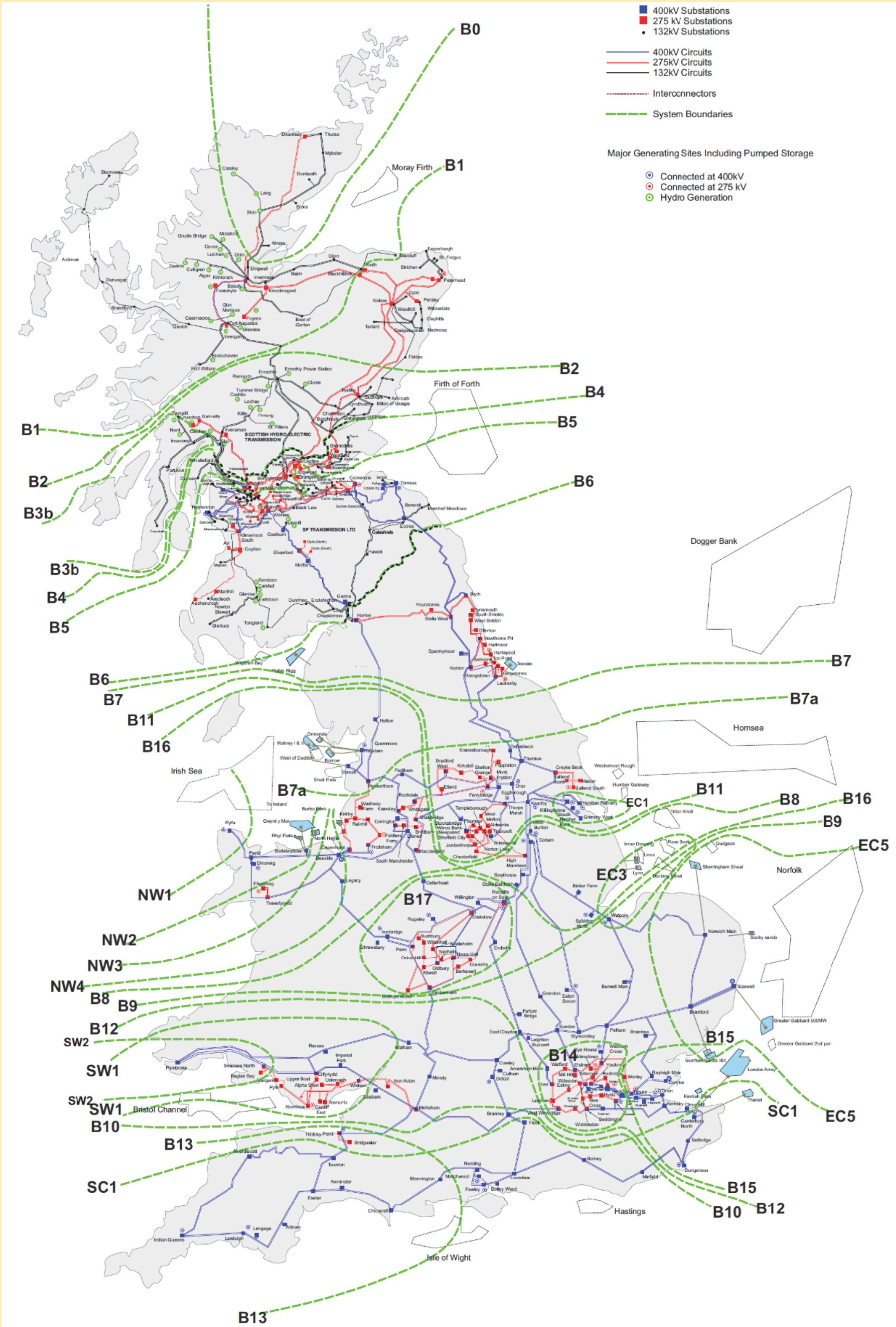
D.3.2.1 Reactive power compensation data

With reference to the analysis in 'Annex 2b.iii' and with particular reference to the use of SVC systems in the following sections, some notes and information are discussed relating to the implementation and use of these FACTS devices in a significant transmission network as that of NGC, UK [9].

The configuration of the transmission network system is shown in Figure 23.

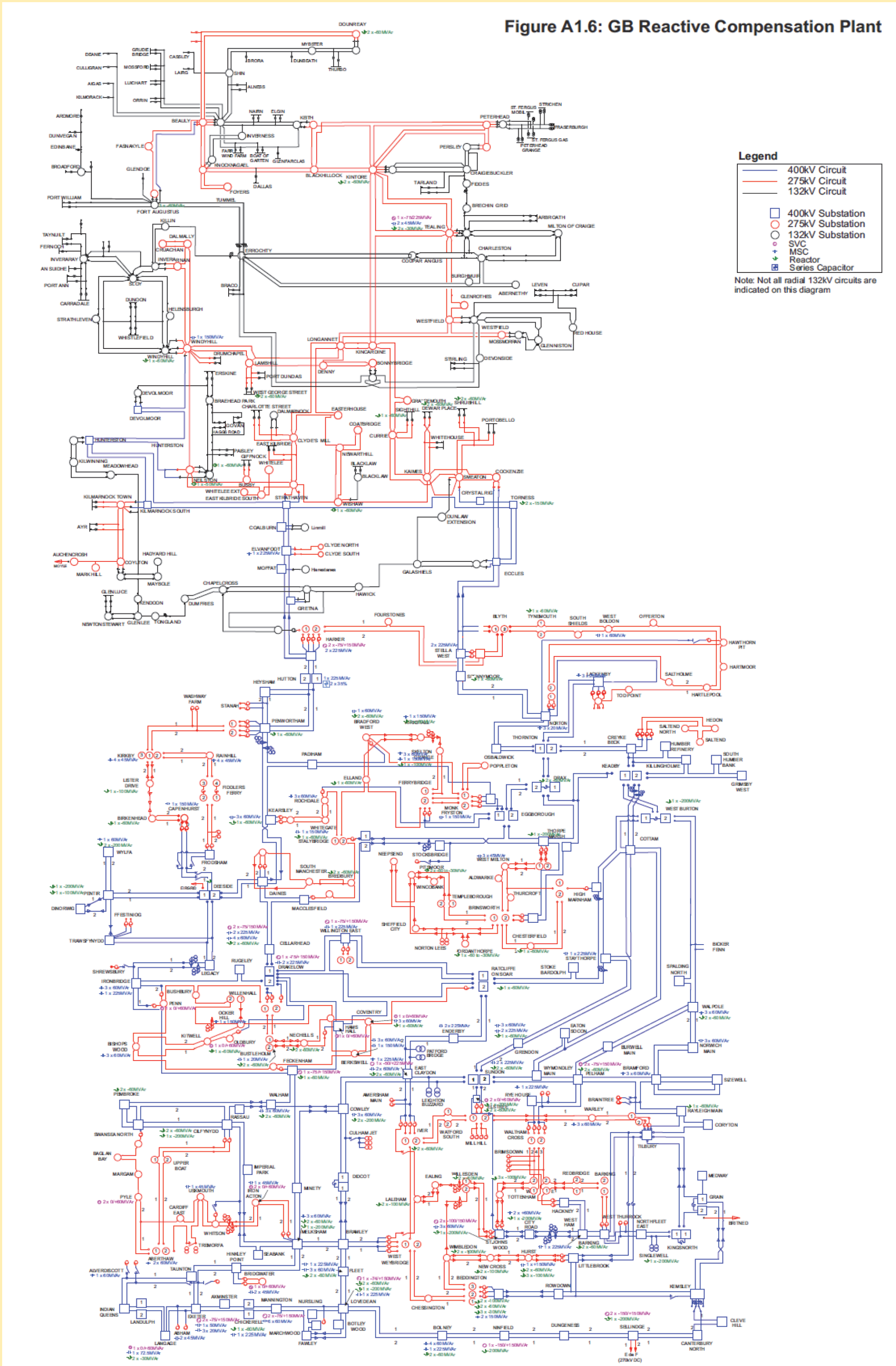
The schematic below Figure 24 shows the rating and localization of reactive power compensation systems based on the configuration of the 400/275 and main 132 kV systems in UK.

FIGURE 23: UK NGC TRANSMISSION MAP



Source: National Grid – UK, 2014, (6)

FIGURE 24: UK REACTIVE COMPENSATION MAP



Source: National Grid – UK, 2014, (6)

Reactive power compensation and system voltage control is obtained with a combination of:

a. Reactors, both connected directly to HV or to Tertiary windings of transformers (60 Mvar/33 kV, 60 Mvar/132 kV, 100 Mvar/275 kV, 150 Mvar/400 kV);

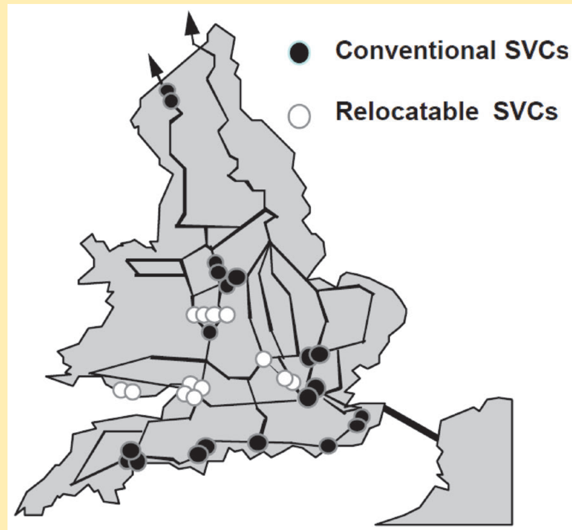
b. Mechanically Switched Capacitors (45-60 Mvar/132 kV, 150 Mvar/275 kV, 225 Mvar/400 kV); and

c. SVCs (typically 150 Mvar connected through a dedicated transformer to 275 or 400 kV, and 60 Mvar, connected to tertiary winding of substation transformer).

There are 40 installed SVCs with a total installed capacity of more than 4,000 Mvar, roughly a third of the Reactive power provided by the remaining mechanically Switched Capacitors, to be compared with a total installed capacity of around 93 GW, to serve a peak demand of around 60 GW.

A systematic installation of reactive compensation systems in the event of substantial expansion phases of the network or in case of significant increase in the load served in a certain area of the grid adopted by NGC allows for the efficient use of the network assets, satisfying locally, as far as possible, any request for a reactive power demand that is not covered for example at the level of the distribution network. Then, the option to install a FACTS device instead of a traditional mechanically Switched Capacitors is normally considered and activated in the nodes where the network analysis shows the presence of major problems in the control of voltage profiles and thus the need to provide rapid support of the related regulation.

FIGURE 25: UK SVC LOCATION MAP



Source: Cigrè, 2000, (7)

Figure 25 identifies the location of the SVCs within the UK.

D.3.2.2 New SVCs installation

The table in Figure 26 shows the anticipated incremental changes and implementations, scheduled over the next decade and concerns the reactive power equipment within the SVC installation.

FIGURE 26: UK SVC DEVELOPMENT PLAN 2014-2024

Reactive Compensation Equipment, 2015/16 to 2023/24								
SHE								
Site Name	**Change Type**	**Year**	**Node**	**Unit Number**	**MVAr Generation**	**MVAr Absorption**	**Compensation Type**	**Connection Voltage (kV)**
TUMMEL	Addition	2018	TUMM2J	1	225	75	SVC	275
NGET								
Site Name	**Change Type**	**Commissioning Year**	**Node**	**Unit Number**	**MVAr Generation**	**MVAr Absorption**	**Compensation Type**	**Connection Voltage (kV)**
Drakelow	Removal	2015	DRAK21	6	150	-75	SVC	275
Bolney	Addition	2018	BOLN40	1	75	75	SVC	400
Ninfield	Addition	2018	NINF40	1	75	75	SVC	400
Richborough	Addition	2020	RICH40	1	75	75	SVC	400
OFTO								
Site Name	**Change Type**	**Commissioning Year**	**Node**	**Unit Number**	**MVAr Generation**	**MVAr Absorption**	**Compensation Type**	**Connection Voltage (kV)**
Galloper	Addition	2017		1	50	50	SVC	132
Galloper	Addition	2017		2	50	50	SVC	132
Galloper	Addition	2017		3	50	50	SVC	132
Necton	Addition	2017		1	95	95	SVC	132
Necton	Addition	2017		2	95	95	SVC	132

Source: ENTSO-National Grid - UK, 2014, (6) The installation or relocation of a further 10 SVCs is planned within this scenario, where a combination of different systems is also anticipated.

D.3.2.3 NGC strategy for reactive power compensation

NGC plans the use of FACTS devices to address specific issues related to the operation of the network, as shown in the table labeled Figure 27.

The strategy that is the basis of the application of FACTS devices can be summarized in the following two NGC statements.

"Reactive power compensation devices provide voltage support when voltage needs to be increased or decreased. This might be during the minimum demand periods when voltage is often too high or after a fault when there is rapid and significant voltage depression that needs reactive power injection to recover the voltage level as quickly as possible. This response can be provided by a range of devices, such as capacitors, reactors, Static VAr Compensators (SVCs), static synchronous compensators (STATCOMs), or generation assets. These devices have various capabilities and the best solution is chosen based on the type of voltage management required and the local system parameters".

"Network reinforcement is not just about new capacity but can also mean releasing the latent capability of the system. This is achieved by enabling technologies, which do not deliver capacity alone, but as part of a network will improve transfer capacity or improve stability, which will allow higher boundary transfers. Where network parameters such as voltage, fault tolerance or stability are the limiting factors then reactive compensation can be used to improve regulation and thereby regional power capacity. Static VAR compensators (SVCs) and STATCOMs are used to retain voltage stability during fault conditions. In marginal cases, this can avoid the need for new circuits for security of supply".

The illustration in Figure 28 shows the contribution provided by two of the installed SVCs, namely the SVCs at Harker substation, 2 x 150/-75 Mvar, that provide significant support to the transient and dynamic stability margins, increasing the power transfer limits from Scotland to England, thus addressing the unbalanced distribution of generation in the north and the primary load present in the southern part of the grid [10].

D.3.2.4 Re-locatable SVCs

Some comments can be made with reference to the specific development of standardized re-locatable solutions.

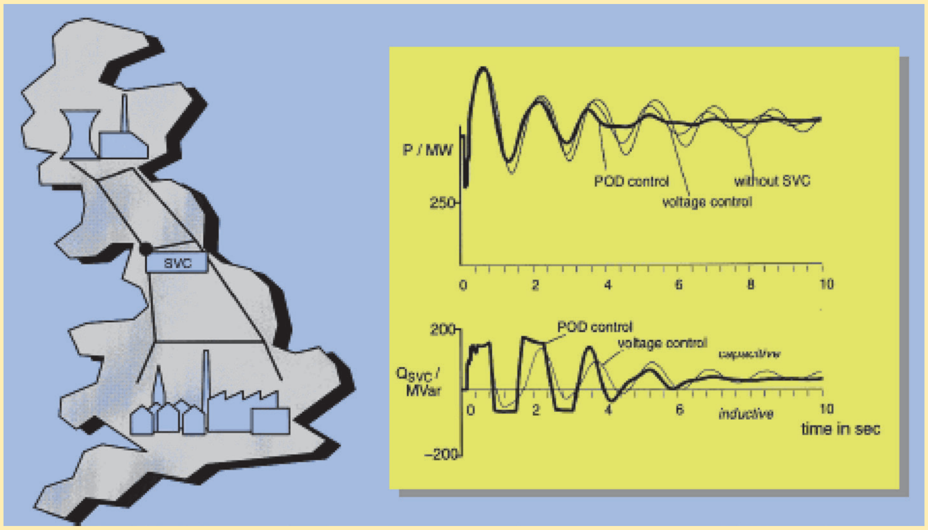
FIGURE 27: NGC SELECTED TRANSMISSION SOLUTIONS

Potential transmission solutions

Category	Transmission Solution	Nature of Constraint			
		Thermal	Voltage	Stability	Fault Levels
Low Cost Investment (Operational)	Coordinated quadrature booster schemes	✓	✓		
	Automatic switching schemes for alternative running arrangements	✓	✓	✓	✓
	Dynamic ratings	✓			
	Enhanced generator reactive range through reactive markets		✓	✓	
	Fast switching reactive compensation		✓	✓	
Commercial	Availability contract	✓	✓	✓	
	Inter-tripping	✓	✓	✓	
	Reactive demand reduction		✓		
	Generation advanced control systems	✓	✓	✓	
Asset Investment (Onshore/ Offshore)	Hot-wiring overhead lines	✓			
	Overhead line reconductoring or cable replacement	✓			
	Reactive compensation (MSC, SVC, Reactors)		✓	✓	
	Switchgear replacement	✓	✓	✓	✓
	New build (HVAC/HVDC)	✓	✓	✓	✓

Source: National Grid - UK, 2014, (6)

FIGURE 28: EXAMPLE OF TRANSIENT STABILITY ENHANCEMENT

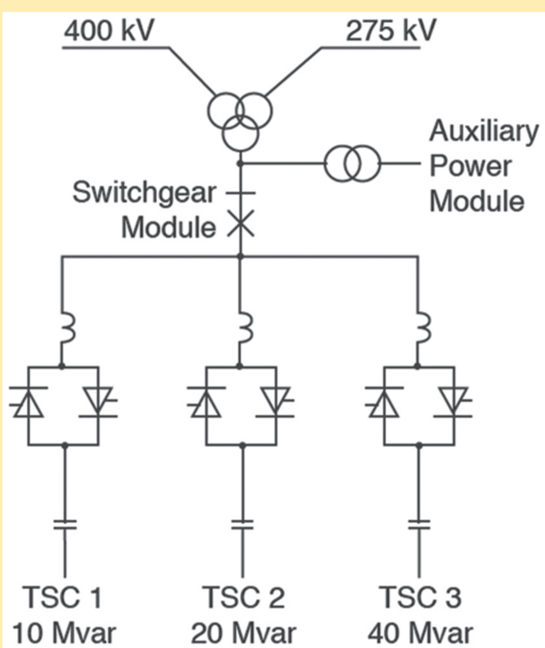


Source: Cigrè, 2000, (7)

The development of these solutions was started in the 90's in order to address the need for an additional degree of flexibility in the planning of the network required mainly because of the introduction of the unbundling of the assets of the electrical system.

The first family of re-locatable SVCs introduced in the grid was based on TSC modular systems with a rated power of around 60 Mvar and directly connectable to the tertiary winding of the existing substation transformer [11]. The typical connection schema is shown in Figure 29, whereas the typical lay-out, based on modular skids, transportable by truck, is shown in Figure 30.

FIGURE 29: RE-LOCATABLE SVC CONNECTION SCHEME



Source: CigrèABB, 2013, (8)

The following steps have led to the increase of SVC rated power to values of 150 up to 225 Mvar with the possibility of connection via dedicated transformer to the 400 or 275 kV network.

In this case the basic requirements set by NGC were relevant to:

a. A wider operating range with higher reactive power output;

b. The availability of faster dynamic response characteristics;

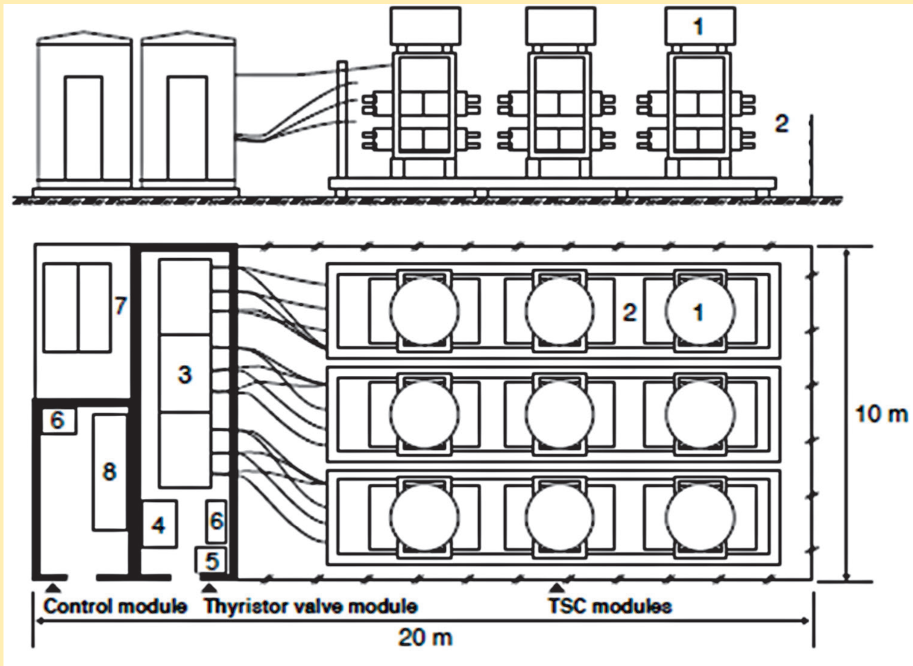
c. A modular converter design to allow for a wide range of selectable ratings;

d. Re-locatable cabin-based design to assure maximum operational flexibility with the ability to relocate within 6 months; and

e. Availability > 98%.

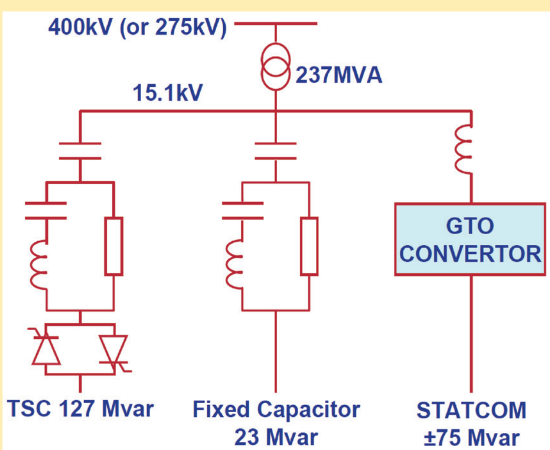
The resulting system schema, shown in the following Figure 31 saw the introduction of a STATCOM device (equipped with GTO or IGBT's), which ensures greater system functionality [12]. The corresponding lay-out remains very compact, as shown in Figure 32.

FIGURE 30: RE-LOCATABLE SVC TYPICAL LAYOUT



Source: ABB, 2013, (8)

FIGURE 31: RE-LOCATABLE SVC EQUIPPED WITH VOLTAGE SOURCE CONVERTER



Source: ALSTOM, 2013, (9)

FIGURE 32: RE-LOCATABLE SVC EQUIPPED WITH VOLTAGE SOURCE CONVERTER. TYPICAL LAYOUT

Source: ALSTOM, 2013, (9)

D.3.2.5 Optimal strategy for reactive power compensation, lessons learnt

The following main points emerge from the analysis of the experience of the UK, regarding the optimization of the reactive power management.

Reactive power compensation devices have various capabilities and the best solution should be chosen on the basis of the specific type of voltage management required within the context of the local system parameters:

a. For "strong" nodes and areas where there are no problems with voltage regulation or there is the availability of local generating units that may participate in the voltage regulation, the installation of the traditional mechanically Switched Capacitor is more than enough to ensure the correct reactive power compensation, with the least economic impact but with good management of the transmission grid asset.

b. It is possible to identify some nodes or network areas where the ability to rapidly adjust the contribution in the exchange of reactive power is important to ensure the stability of the network and therefore the installation of FACTS devices becomes the most suitable option.

c. In contexts where the configuration of the network changes very rapidly and substantially, in particular in the case of connections of large renewable energy sources, this kind of solution becomes offers the most flexible approach.

d. This is especially true in all cases where there is the need to compensate for rapid fluctuation of load or generation, which impacts the level of power quality.

When a network reinforcement is required it is traditionally achieved by installing new standard equipment, i.e. lines and new substation bays, but a different approach can be considered in some cases, that is both more practical, convenient and which unleashes the latent capability of the existing system.

This is achieved by applying enabling technologies, which do not deliver capacity alone, but as part of the network, improve transfer capacity or stability and which allow higher boundary transfers.

Where network parameters such as voltage, fault tolerance or stability are the limiting factors then reactive compensation and in particular FACTS devices (e.g. SVC) can be used to improve regulation and thus regional power capacity.

One factor that has often limited the use of FACTS devices apart from their high cost is the risk that a rapid development and expansion of the transmission grid could make these devices redundant at the installation node after a few short years following their commissioning, thus making the investment both uneconomical and unattractive when compared with more traditional alternatives.

A solution that could limit this risk and in turn optimize the use of FACTS devices is the application of re-locatable or semi-portable systems. In this way, these systems can be quickly installed/or moved to network nodes that reveal operational problems, resolving the issues in the short term, while allowing the implementation of other more strategic structural network reinforcements that require longer completion times.

D.4 USA

The USA's electrical network is comprised of a large number of transmission systems and in most cases the TSO organizational structure is comprised of an ISO that controls a number of WOs. Whilst such a network structure is quite unlike both the Italian and Vietnamese models, it could still serve as a best practice benchmark for the development of some strategic or tactical projects within the Vietnamese system.

The experiences in the USA offer examples of best practice as follows:

a. PMU installations and the subsequent development of the WAMS application;

b. Two different projects regarding Dynamic Line Rating;

c. The BC Hydro case is a good reference to evaluate the opportunity to install sensors for on-line DGA on new and old power transformers; and

d. A new type of application developed with HVDC systems.

D.4.1 Phase Measurement Units—NASPI roadmap

Following a blackout in 2003 in North Eastern United States and Eastern Canada the NASPI (North American Synchrophasor Initiative) roadmap was developed based on NERC (North American Electric Reliability Corporation) priorities and goals (shown in Figure 33).

NERC is the electricity reliability organization for North America and its jurisdiction includes users, owners, and operators of the bulk power system that serves more than 334 million people [13]. It is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America. Its responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico.

FIGURE 33: NERC PRIORITIES AND GOALS

NERC and Committee Priorities and Goals	Phasor Technology Role
NERC President's Priority Issues • Misoperation of relays and control systems • Human errors by field personnel • Changing resource mix • Integration of new technologies • Prepare for high-impact, low frequency events	• Identify relay mis-operation and events • Monitoring & situational awareness • Assist operator response • Improve system, plant, dynamic models • Back up & complement SCADA systems
NERC Operating Committee Priorities • Voltage stability • Human error • Seams issues • Coordination of outages	• High-speed monitoring for wide-area situational awareness • Data analysis for fast operator decision support tools
NERC Planning Committee Priorities • Reliability assessments • Technical planning analyses • Event analysis • NERC alerts • Transmission system protection • Frequency response • Model validation	• Time-synchronized, accurate, detailed data on actual grid events and normal system behavior for event analysis and model validation • Identify system dynamics • Mine data to design limits, alerts • Identify and understand frequency response and oscillatory behavior

Source: NASPI, 2011, (10)

Starting with these priorities and goals NASPI developed its Synchrophasor roadmap. The first one was defined in 2006 and took account of priorities, challenges, timescales and costs of each proposed application. They initially defined a list of applications to be created and identified the components to be installed.

For all of these applications they set:

a. Priority: Needs and Criticality;

b. Deployment challenges; and

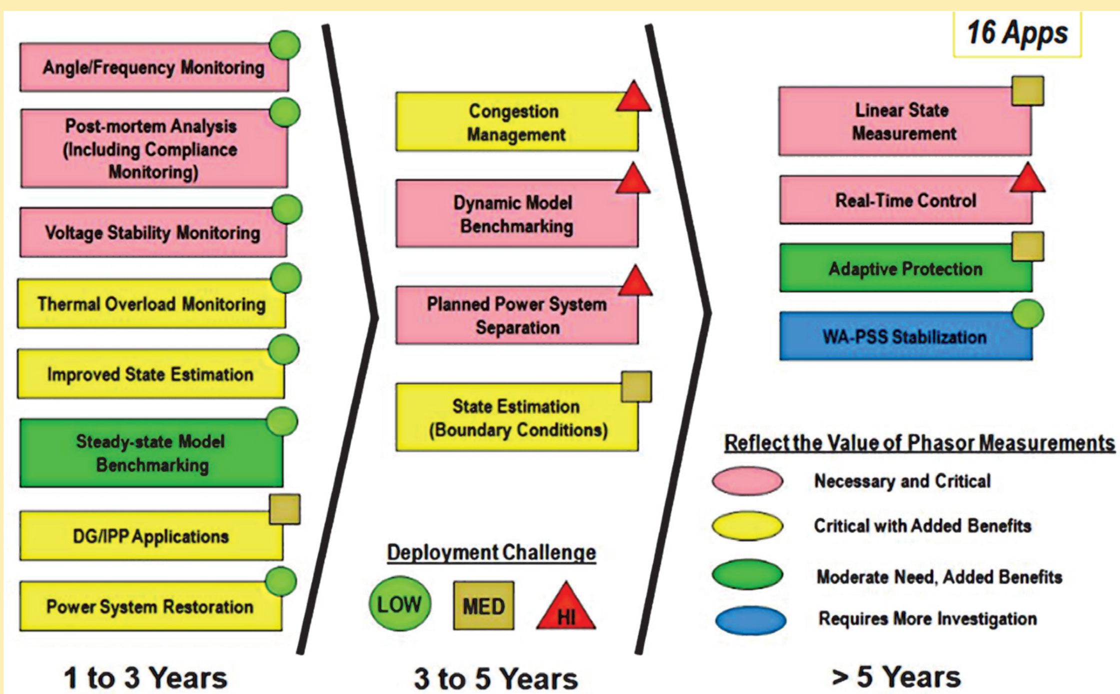
c. Time to complete.

In this way NASPI was able to design a "Phased roadmap", as shown in Figure 34.

A further and more complete roadmap was developed in 2012 that introduced 26 applications to be implemented over 5 years (as shown in Figure 35).

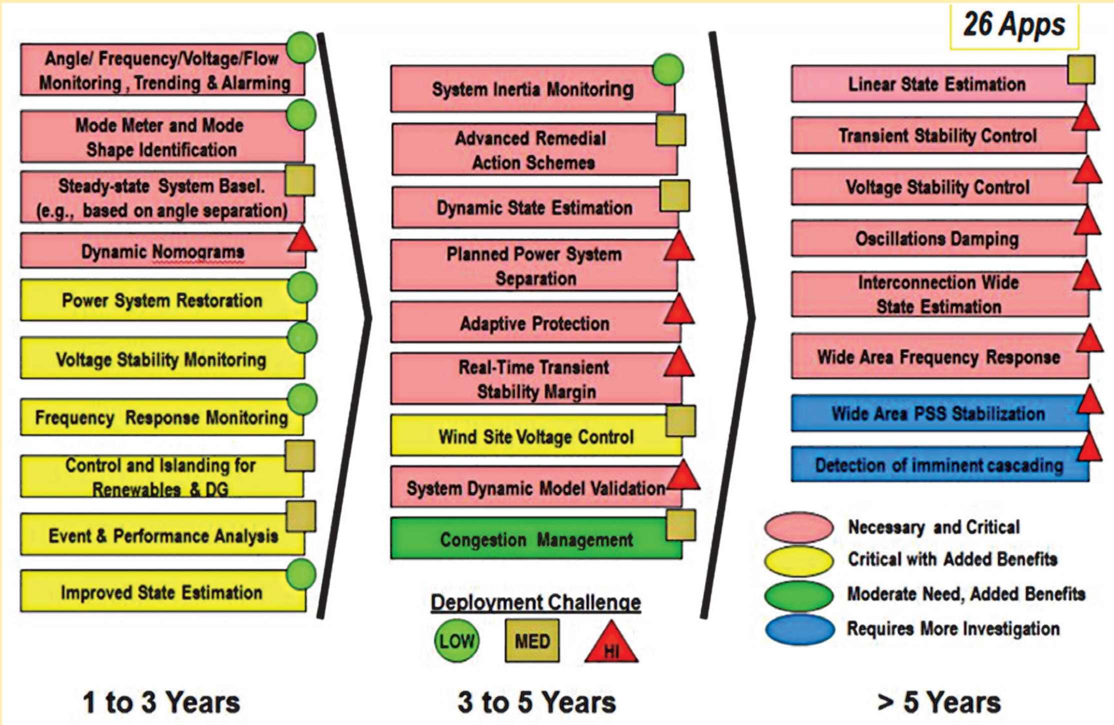
It is a useful exercise to analyse this roadmap as much for its approach as for the high number of applications identified. The most interesting feature is that NASPI

FIGURE 34: 2006 NASPI ROADMAP



Source: Cigrè, 2013, (11)

FIGURE 35: 2012 NASPI ROADMAP



Source: NASPI, 2014, (12)

prioritized the applications that were most significant in the context of NERC's priorities and goals.

They then prioritized the applications on a timeline and thus created a phased roadmap. This is very important because it takes account of all the different aspects of implementation (necessity, deployment challenge, time to complete) and allows effort to be focused on those challenges that need attention first.

Furthermore, this approach also created a complete plan that predicted when particular applications would be available and reduced the degree of uncertainty in their development.

The NASPI project approach also demonstrates that it is useful to revise and modify the roadmap during the lifetime of its implementation in order to add further applications that arise from the experience of the on-going activities to date and which address the emerging needs of the evolving network structure and behavior.

For example, the experience acquired during the Smart Grid implementation process added more detail to already developed applications like "Angle/Frequency Monitoring" which then evolved into "Angle/Frequency/Voltage/Flow Monitoring, Trending and Alarming", or added some dedicated applications for a specific need (like "Mode Meter and Mode Shape identification") that was previously merely an ancillary function of another application but which evolved into a discreet requirement in the second iteration of the roadmap. Moreover, the growth of the network during the lifetime of the roadmap implementation gave rise to new requirements, such as "Wind Site Voltage Control", that had not even been considered in the first iteration.

Further, this iterative revision process allows needs and criticalities to be constantly reviewed and re-evaluated. For example, "Adaptive Protection" application, which in the first roadmap was deemed a medium priority with a medium development difficulty, had, in the revised roadmap, become a critical need and reassigned as a high development challenge. On the other hand the "Congestion Management" application that in the first revision of the roadmap was both critical and difficult to implement had become less important and easier to deploy in the 2012 iteration.

Finally, this revision process is also a useful way of measuring and monitoring the performance and relevance of the roadmap in the dynamic context of present day needs and exigencies. An example is how the "Voltage Stability" application became increasingly less critical over the two iterations of the roadmap probably as a function of the experiences acquired with the subject during the lifetime of the iterations of the roadmap.

D.4.1.1 Investments and accomplishments

The SGIG (i.e. Smart Grid Investment Grant) synchrophasor projects were included as part of the NASPI project set [14], [15]. Thanks to SGIG there are ten more synchrophasor projects underway involving 57 utilities and grid operators across the U.S. These projects have installed about 850 networked PMUs which, by 2013 were operating in nearly all regions of the country.

The total budget of the SGIG projects is more than $300 million and includes 50% from Recovery Act funding which made the projects collectively the single largest synchrophasor effort ever undertaken. The American Recovery and Reinvestment Act of 2009 provided the DOE with $4.5 billion to fund projects that modernized the Nation's energy infrastructure and enhanced energy independence.

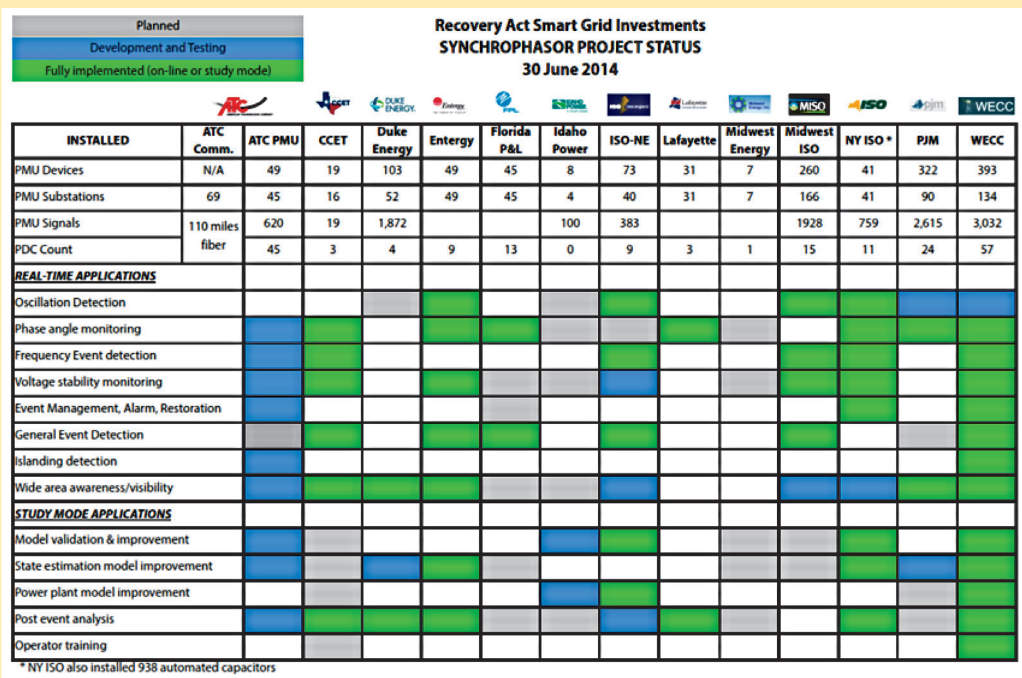
The next two figures (Figure 36 and Figure 37) show the project investments of different utilities and the applications implemented.

FIGURE 36: NASPI ROADMAP: "INVESTMENTS 2010-2013"

Project lead	Project investment (federal and private) ($1,000)	# Transmission owner partners	Total PMUs by 2014
American Transmission Co. (*2 grants)	$ 25,550 *	1	45
CCET (ERCOT -- * regional demo grant)	$ 27,419 *	3	23
Duke Energy Carolinas	$ 7,856	1	104
Entergy Services	$ 9,222	1	45
FP&L (* regional demo grant)	$ 578,963 *	1	45
ISO New England	$ 8,519	7	39
Midwest Energy	$ 1,425	1	7
Midwest ISO	$ 34,543	10	165
New York ISO	$ 75,712	8	39
PJM	$ 27,840	12	81
WECC	$ 107,780	18	439

Source: NASPI, 2011, (10)

FIGURE 37: NASPI ROADMAP: "APPLICATIONS ON PMUS"



Source: U.S. Department of Energy, 2014, (13)

Main application achievements are in the following areas:

a. Real time observation of system performance;

b. Early detection of system problems;

c. Real time determination of transmission capacities;

d. Analysis of system behavior, especially major disturbances;

e. Special tests and measurements; and

f. Refining of planning, operation, and control processes essential for best practice in the use of transmission assets.

It is worth noting that there are a significant number of possible applications that can use WAMS data, which is why PMU installation greatly increases the potential for effective monitoring and control of the network. The result of the deployment of such applications, in fact, aims to reduce grid congestion, permit more electricity to flow through existing wires and provide early warning of disturbances to enable timely preventative or remedial actions.

D.4.1.2 Lessons learnt

The table in Figure 37 shows that of all the ISOs that joined NASPI, the WEEC (Western Electricity Coordinating Council) succeeding in implementing the largest number of planned applications. But the real added value of the NASPI experience is the strategy behind the planning of a very large organization involving a group of ISOs that installed PMUs and developed applications for their individual WAMS projects whilst adhering to shared objectives.

Furthermore, the experiences acquired during the implementation process were shared in order to revise the roadmap in terms of priorities, deployment challenges and time to complete of the application planned. This is a good reference point even for smaller organizations such as a single TSO where all the different functions contribute their experiences and emerging understanding to the periodic review of the roadmap with a particular focus on how the experiences gained during its implementation have changed their perceptions of application priorities, deployment challenges and timescales.

Finally, the NASPI experience highlighted the importance of interoperability, which is paramount for synchrophasor technologies to succeed, as data must flow across multiple transmission system owners' synchrophasor systems, transmission systems, and communications networks. Towards this end many NASPI members have been working with the National Institute of Standards and Technology Smart Grid interoperability standards in an effort to accelerate development of new technical standards for synchrophasor data, equipment and systems.

D.4.2 Devices for Dynamic Line Rating— NYPA and Oncor DTCR projects

Among all the possible Smart Grid applications Dynamic Thermal Circuit Rating (DTCR), also known as Dynamic Line Rating (DLR), is one of the most significant thanks to its ability to enable transmission system operators/owners to mitigate or avoid the costs associated with transmission system congestion.

The U.S. experience with this subject is very instructive. The New York Power Authority (NYPA) and Oncor Electric Delivery Company (Oncor), through the U.S. Department of Energy's Smart Grid Demonstration Program (SGDP), implemented two demonstration projects [16]. They installed dynamic line rating (DLR) technologies to increase the efficient use of the existing transmission network, mitigate transmission congestion and develop best practices for applying DLR systems.

It is very interesting to analyze both projects because they were developed by two very different companies, the first being America's largest state power organization, with 16 generating facilities and more than 1,400 circuit-miles of transmission lines while the second, Oncor, is the largest regulated electric delivery business in Texas supplying electricity to approximately 7.5 million consumers.

DLR technologies enable transmission owners to determine capacity and apply line ratings in real time. This enables system operators to take advantage of additional capacity when it is available. Both demonstration projects confirmed the presence of real-time capacity above the static rating, in most instances, with up to 25% additional usable capacity made available for system operations.

NYPA worked with the Electric Power Research Institute (EPRI) using technologies and approaches that EPRI had developed, while Oncor deployed Nexans' commercially available conductor tension-monitoring CAT-1 System; Figure 38 provides a brief overview of the two projects.

NYPA's project involved a wider set of DLR technologies whilst Oncor's was larger in scale and aimed for a higher degree of integration with utilities and Independent System Operators (ISO). Figure 39 sums up the main objectives and outcomes of the two projects.

FIGURE 38: PROJECTS DESCRIPTIONS

Key Elements of DLR Demonstrations	DLR Demonstration Projects	
	NYPA	**Oncor**
DLR system developer	EPRI	Nexans
Other partners	♦ EDM International, Inc. ♦ Pike Electric Corporation ♦ NYISO ♦ New York State Energy Research & Development Authority (NYSERDA)	♦ Promethean Devices ♦ EDM International, Inc. ♦ SwRI ♦ Siemens Energy Inc. ♦ Chapman Construction Company ♦ ERCOT
Total installed cost	$481,000	$4,833,000
Total project budget	$1,440,000	$7,279,166
Project duration	1/1/10 – 1/31/13	1/1/10 – 5/4/13
Project location	Three 230 kV transmission line sections in New York	Five 345 kV and three 138 kV transmission circuits in Texas
DLR equipment	♦ 3 Video Sagometer systems ♦ 3 ThermalRate Systems ♦ 9 EPRI Sensors ♦ Weather stations	♦ 27 Nexans CAT-1 units ♦ 5 Video Sagometer systems ♦ 2 RT-TLMS
Communications equipment	♦ Backscatter data loggers, LoggerNet data logging software, and Remote Terminal Units (RTUs) ♦ Ethernet cables connecting data loggers to cell modems ♦ RF Link (to transmit load data to ThermalRate systems) Data was transmitted via Virtual Private Network (VPN)	♦ CATMaster radio/RTU interface ♦ RTUs Data was transmitted via radio frequency to substations, where it was imported to the SCADA system and EMS
DLR software	EPRI's proprietary DTCR software	Nexans' proprietary IntelliCAT™ software
Average increased real-time capacity	30%-44% above static rating based on available field data[6]	8%-12% above ambient-adjusted rating (138 kV lines) 6%-14% above ambient-adjusted rating (345 kV lines)[7]

Source: U.S. Department of Energy, 2014, (14)

FIGURE 39: PROJECTS OBJECTIVES AND OUTCOMES

	NYPA's DLR Project	Oncor's DLR Project
Project objectives	◆ Assess a variety of prototype and commercially available DLR technologies ◆ Demonstrate how DLR technologies could be used in transmission system engineering, operations, and planning at NYPA ◆ Determine a correlation between increased real-time capacity and increased wind generation	◆ Demonstrate the commercial viability of mature DLR technologies, with a focus on Nexans' technology ◆ Automatically utilize dynamic ratings in real-time system operations ◆ Develop a "best practices" guide to facilitate future DLR deployments
Key outcomes	◆ Calculated dynamic ratings and confirmed excess real-time capacity above static ratings ◆ Confirmed positive correlations between dynamic rating and wind farm output, as well as wind farm output and line loading ◆ Identified DLR systems' potential to facilitate the integration of wind generation, define more effective static line rating methodologies, and support transmission planning studies	◆ Calculated dynamic ratings and confirmed excess real-time capacity above ambient-adjusted ratings ◆ Integrated dynamic ratings into the system operator's economic dispatch tool for automatic utilization in real-time operations ◆ Confirmed that a fully integrated DLR system is commercially viable ◆ Determined that DLR systems are economically valuable, even though the financial benefits may be difficult to quantify ◆ Identified DLR systems' potential to facilitate the integration of wind generation, mitigate congestion, and improve grid reliability ◆ Developed a "best practices" guide to facilitate future DLR deployments

Source: U.S. Department of Energy, 2014, (14)

D.4.2.1 NYPA project

NYPA was interested in studying DLR technologies because the utility transfers significant amounts of power (particularly power generated by hydroelectric plants in northern New York and wind farms in western and northern New York) across great distances to the south-eastern New York population centers within a historically constrained transmission system.

The project was launched in 2010 and concluded at the end of January 2013. One of the most important NYPA discoveries is that whilst DLR technologies are reliable, the learning curve to implement them is significant. So it is crucial to perform a detailed analysis to determine if a particular line is a good candidate for increased real-time capacity before procuring and installing the technology which then have to be properly operated and maintained.

NYPA's project involves many types of DLR devices, so their performance and reliability had been exhaustively investigated. Most of NYPA's reliability concerns were with its own communications devices but all of the DLR devices also experienced reliability issues. In most cases, these issues were related to the significant learning curve for deploying a DLR system, rather than to the design or quality of the devices.

The use of new devices led NYPA to perform an assessment of the DLR equipment installation process. NYPA's line crews did not have experience of the specialized instruments required for DLR systems so they received comprehensive training from EPRI. The installation process itself was improved and streamlined and overall NYPA determined that a well-trained line crew could install certain types of DLR devices without causing any outages or drop-outs. Furthermore the training process for and knowledge transfer of DLR technologies was crucial for the NYPA control center.

The main aim of NYPA is to use dynamic ratings to determine a correlation between increased wind generation and increased transmission capacity. The knowledge of this relationship could inform transmission planning studies and encourage higher expenditures on transmission projects. Figure 40 below shows how the thermal constant of the lines depends basically on wind and, consequently, the maximum capacity gain of the lines is achievable in the presence of high wind.

NYPA has demonstrated that a small project with very specific and clear objectives can enable the comprehensive testing of a number of DLR devices, which could eventually be used in future projects on a larger scale. This has proved useful for planning strategies. Once again this is a good example of cooperative interaction between different functions of a TSO: i.e. operation, asset management, grid construction and planning.

FIGURE 40: FACTORS INFLUENCING THE DYNAMIC RATING

Operating Conditions	Change in Conditions	Impact on Capacity
Ambient temperature	2 °C decrease	+ 2%
	10 °C decrease	+ 11%
Solar radiation	Cloud shadowing	+/- a few percent
	Total eclipse	+ 18%
Wind	3 ft./s increase, 45° angle	+ 35%
	3 ft./s increase, 90° angle	+ 44%

Source: U.S. Department of Energy, 2014, (14)

D.4.2.2 Oncor's project

Oncor's project, on the other hand, required about ten-times the investment of NYPA's project and was primarily based on Nexans' CAT-1 System. The CAT-1 Transmission Line Monitoring System allows accurate real-time rating of transmission lines by monitoring the mechanical tension of both ruling span sections of a dead-end structure. Thus, sags, clearances and average conductor temperature are all directly related to CAT-1 measurements while the actual line rating is calculated using this information together with data from the EMS/SCADA system.

The aim of the project was to remove the constraints that prevent utilities from using DLR technologies and to demonstrate the effective use of dynamic ratings to reduce grid congestion. In particular Oncor was interested in implementing a DLR system because many of its transmission paths, including those selected for this project, were suffering from significant transmission capacity constraints.

Oncor discovered that the average increased real-time capacity delivered by dynamic ratings was 6%-14% greater than the ambient-adjusted rating for 345 kV lines and 8%-12% greater than the ambient-adjusted rating for 138 kV lines.

The availability of the added capacity ranged from 83.5% of the time under all operating conditions to 90.5% of the time when outages and anomalies were excluded from the calculations. Those increased capacities can be safely delivered within a market structure while ensuring lines will always be operating within their safety limits.

Oncor did not want to evaluate DLR technologies, rather it sought full-scale and real-time integration with its own operations and ERCOT's (a Texas ISO) wholesale electricity market. So the most significant outcome of Oncor's project was the integration of a DLR system with ERCOT's control room. This direct feed to transmission owners' communication and control systems, in fact, eliminated the need for the operator to manually view, interpret, and apply the dynamic rating.

D.4.2.3 Lessons learnt

To conclude, the key outcomes of the two SGDP projects were NYPA's assessment of the benefits and disadvantages of DLR technologies and Oncor's demonstration that dynamic ratings can be automatically applied in real-time system operations.

The two projects revealed opportunities to enhance future DLR deployments by ensuring the reliability of DLR data, pre-emptively addressing cyber security concerns, integrating dynamic ratings into system operations and verifying the financial benefits of DLR systems.

The verification of the actual financial benefit of DLR systems to the transmission grid and to system operators is probably the biggest challenge. The capacity gained by dynamic ratings can be quantified, and the availability and reliability of the technology and instrumentation can be measured. However, the economic benefit in real time is difficult to quantify, especially as it relates to congestion mitigation. This is because system operators are not currently able to perform real-time "what-if" scenarios of economic benefits with or without dynamic ratings.

Furthermore, the congestion of transmission lines is so volatile and transient that it is difficult to compare current and historical grid operations and congestion costs. Predicting future grid capabilities is even more challenging.

Another challenge is verifying the financial benefits of DLR technologies to the transmission owner. A good approach is to calculate the cost savings that DLR systems unlock thus precluding the immediate need for more extensive capital investments. Figure 41 compares different approaches to increasing ratings through line rebuilds, reconductorings, and DLR installations.

It is worth noting that the installation of DLR systems is often only a fraction of the cost of other solutions although the increase in capacity is less than with other transmission upgrades.

D.4.3 Sensors for on-line Dissolved Gas-in-oil Analysis—BC Hydro case

Power transformers are critical to the electric power system and the utilities are focused on reliability-centered maintenance of their assets for extended lifespans and maximum return on investment. The deterioration of a transformer's internal components results in the production of combustible gases that dissolve in the transformer's oil. Because of this, utilities have long incorporated transformer oil testing into their asset management programs.

Asset managers have learned from experience that checking for fault gases just occasionally is not always sufficient to detect problematic conditions that may develop quite rapidly (i.e. in days or hours). In response to this issue, utilities have begun installing monitoring systems that perform remote dissolved gas analysis (DGA) on a near-real-time basis and transmit results to central monitoring stations.

FIGURE 41: ALTERNATIVE SOLUTIONS COMPARING

Line Type	Alternative Description	New Rating (% Static)	Cost per Mile
138 kV Lattice, Wood H-Frame	Reconductor Aluminum Conductor Composite Core (ACCC) cable	193%	$321,851
	DLR	110%	$56,200
138 kV Wood H-Frame	Rerate 125 °C Modify structures	130%	$10,561
	Rerate 125 °C Replace structures	130%	$6,919
	Rebuild	209%	$750,000
	DLR	110%	$29,471
138 kV Wood H-frame	Rebuild	140%	$237,871
	DLR	110%	$16,767
138 kV Wood H-Frame	Reconductor	212%	$750,000
	DLR	110%	$28,323
345 kV Lattice Tower	Raise structure heights	120%	$73,600
	DLR	110%	$26,626

Source: U.S. Department of Energy, 2014, (14)

Many utilities have chosen to equip only the transformers generally considered to have age related problems with remote monitors. The investment cost at US$55,000 per unit is in fact quite significant. On the other hand, there are justifications for the wide use of monitoring systems of which the main one is the necessity to validate the effectiveness of maintenance programs on transformers of any age.

Viewed in comparison to the cost of replacing a transformer, remote monitoring devices are a fraction of the cost of replacing the transformer, which is in the order of $2-$3 million and entails about two-year lead time.

Therefore some utilities are considering the value of on-line DGA as part of their maintenance programs. At BC Hydro, an incident with a transformer that was nowhere near the end of its life cycle showed the value of monitoring such units in general.

Four generator transformers are installed at BC Hydro's Seven Mile Generating Station. The 225-MVA T1, T2 and T3 transformers were installed in 1978, and the 233-MVA T4 transformer was installed in 2003. All four transformers were equipped with gas detector relays.

In 2004 T1 had a gas relay alarm caused by an internal short circuit between the core and the frame due to failed or contaminated insulation. In 2011, T2 had a gas relay alarm caused by an internal high-voltage bushing failure.

These two events motivated BC Hydro management to examine the other transformers at the station. The utility decided to install eight-gas fault monitors on each of the transformers at the generating station since these two failures had not been detected by traditional oil testing methods.

BC Hydro chose eight-gas monitors for both technical and commercial reasons. In fact measuring the levels of all eight fault gases typically provides a more reliable picture of transformer problems than can be determined by monitoring a single gas such as hydrogen. The gas chromatography system contained in the monitors has been tested and refined over the product's history. Utilities around the world are basing their transformer asset maintenance strategies around these devices.

The installation of on-line DGA monitors in T1 resulting almost immediately in gas level alarms has stressed the need to conduct a detailed investigation of the cause of the problem. On-line DGA has allowed BC Hydro to take prompt and timely preventative remedial actions and to return their power transformer to service within a very short timescale.

The results obtained in this station have proven to BC Hydro that on-line DGA is a financially sound investment. On-line DGA sensors have been shown to be an effective early-warning system that can indicate when maintenance is required and confirm if the maintenance performed was effective.

BC Hydro's experience also shows that monitoring systems can help to extend the life of transformers by enabling them to be run at decreased load until they are replaced or until a permanent repair is made. Prior to the ability to do continuous monitoring the protocol was to rely on laboratory analysis of transformer oil which meant taking the suspect transformer out of service to await the test results.

BC Hydro is considering a plan to specify that every new transformer it buys be installed with an on-line monitor. The utility is also considering an engineering standard to determine when old transformers with gassing concerns need to have on-line monitoring installed to ensure the safe and reliable operation of the transformer. Maintenance managers feel this makes sense when contrasting the modest cost of the monitor with the exponentially higher cost of the transformer.

D.4.4 HVDC application—PG&E Example

Historically, there are many examples of traditional HVDC systems, installed in the USA or cross-border to Canada, both to ensure the interconnection of asynchronous networks, and to allow bulk power transmission across significant distances. However, in the last few years, various transmission network operators in the USA have also had to face some problems similar to those experienced by the Vietnamese grid, where the primary requirement was an increase in the level of transmitted power to large load areas.

Locally no power generation plants were available with sufficient power to support the regulation of system parameters. The most obvious option was to lay new parallel AC connections but this could create serious problems in terms of creating new system operating conditions such as fault current levels beyond the design thresholds of the existing substation, increased risk of a cascade effect in the event of a failure that could cause widespread outages and loops flowing in strongly meshed AC connections.

The technical and economical solution that was finally selected as the most appropriate consisted of a DC (Direct Current) link embedded within the AC network, which connected two synchronous nodes over a short distance. The DC option, in fact, allows for the precise, rapid control and adjustment of the transmitted power along the link, as well as enabling the regulation and stabilization of the parallel AC connections, without increasing the level of short-circuits while introducing a sort of firewall between the two areas thus reducing the risk of disturbances and outages propagating across large sections of the grid.

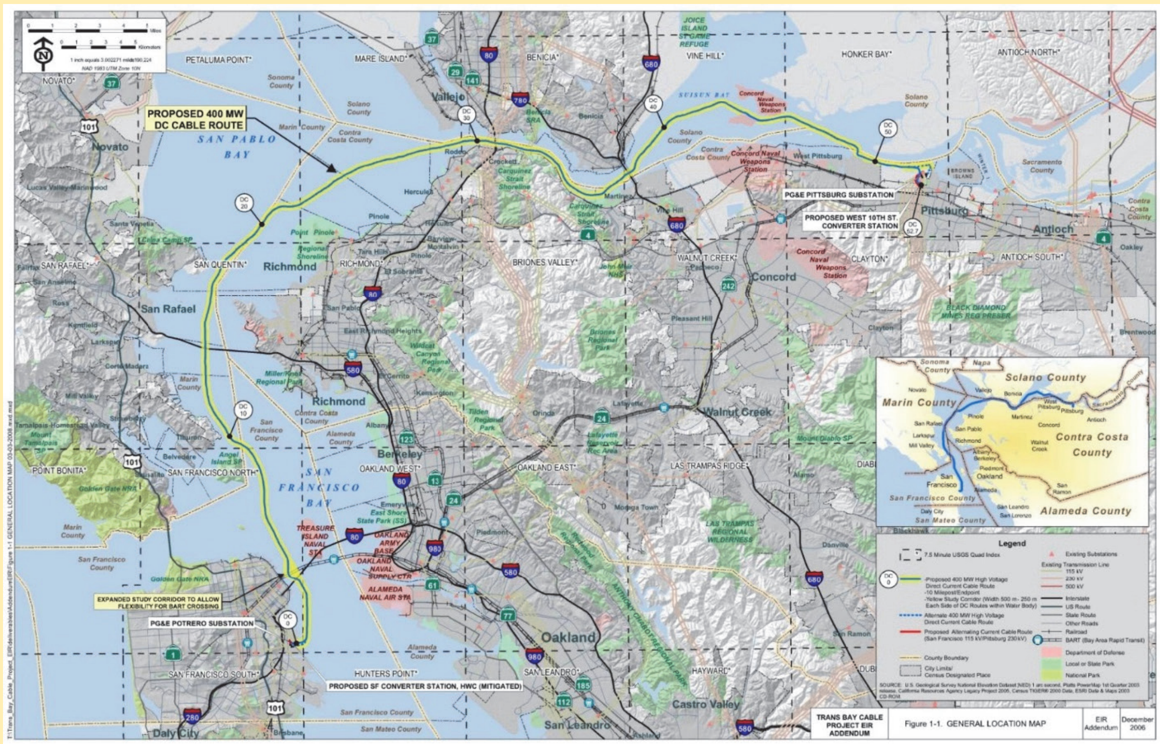
This solution was first introduced in the vast urban areas of New York and San Francisco, but now similar applications are being implemented in other regions including outside the USA. One example of these applications, namely the TRANSBAY project for PG & E in California, is presented here, highlighting the main features and benefits related to the implementation of this type of system.

The configuration of the transmission network system around the San Francisco Bay is shown in Figure 42.

FIGURE 42: SAN FRANCISCO BAY AREA TRANSMISSION GRID

Source: California Energy Commission, 2015, (15)

FIGURE 43: SAN FRANCISCO TRANS-BAY PROJECT



Source: Trans Bay Cable, 2014, (16)

The goal of the Trans-Bay project was to eliminate bottlenecks in the overloaded Californian grid. New power plants were not and still cannot be constructed in this densely populated area, an issue further compounded by the fact that there is no right-of-way for new lines or land cables. This is why a ~90 km DC cable was laid across the bay as shown in Figure 43. The selected configuration ensures more load serving capability than all the other alternatives that had been considered.

The following are the main benefits and specific advantages provided by the selected solution:

a. Controllable Power – Exact power flow from Generation to Load as well as enhanced stability of the AC system. PG&E reported an estimated benefit in economic dispatching of around 55 M$/year;

b. Operational Flexibility;

c. Firewall Protection – AC system disturbances kept confined;

d. No Increase of Short-Circuit Current;

e. Reduced System Line losses. PG&E reported a loss reduction of around 16 M$/year;

f. Inherent Overload Capability (10% continuous overload duty and up to 25% for up to 4 hours) of the selected technical solution;

g. Dynamic Control of Reactive Power/support of AC voltage. The VSC converter is able to provide a large amount of reactive power with completely independent control of the regulation of transmitted active power, as shown in diagram of Figure 44;

h. Reduced System Harmonics generation for full Compatibility with PG&E's San Francisco Area installed SVCs; and

i. Enhanced Reliability, with fulfillment of all the criteria identified considering the N-1 and N-2 contingency analyses, applying standard criteria defined by California ISO (including special criteria for the Greater Bay Area) and WECC.

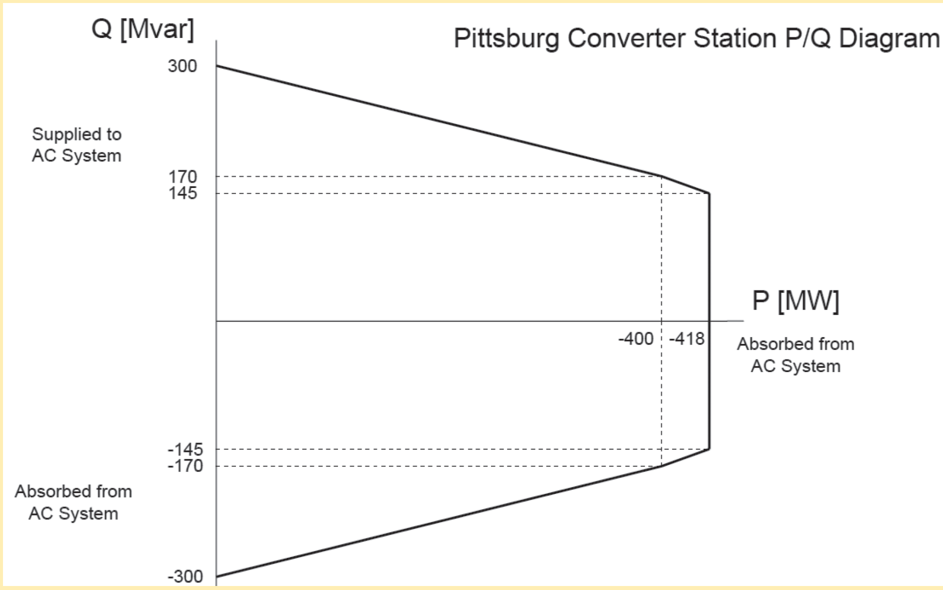
The total investment required for the implementation of the link was approximately $450 million, which included:

a. Components costs;

b. Construction costs;

c. Interconnection Costs at the two terminal stations;

FIGURE 44: VSC P/Q CAPABILITY CURVE



Source: SIEMENS, 2013, (17)

d. Land Costs During Construction;

e. Mitigations and Development Costs;

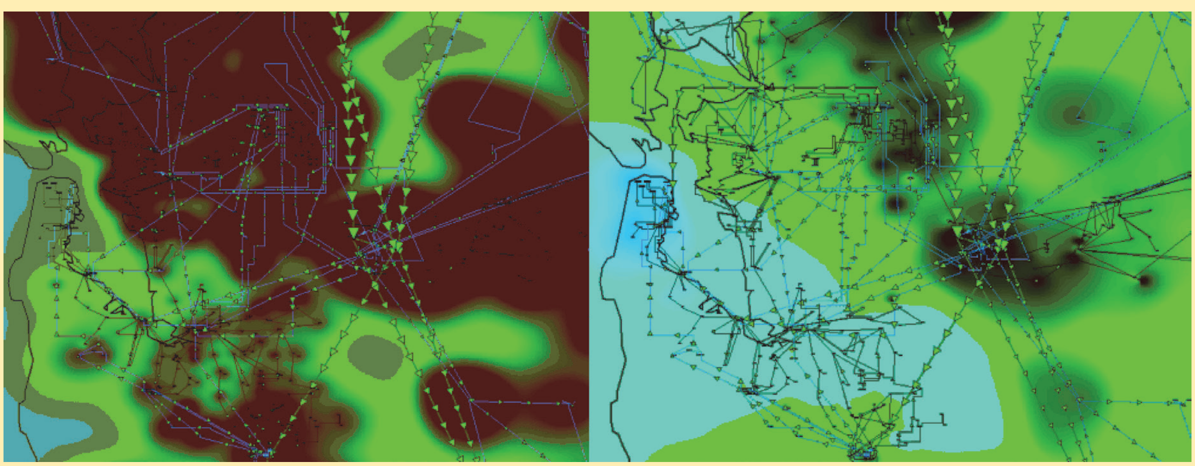
f. Financing Fees and related Costs;

g. Project and Construction Management; and

h. Start-up Costs.

The Trans-bay project completed the Greater Bay Area transmission loop benefiting the entire Bay Area, since system security is increased significantly resulting in reduced power flow on existing Peninsula and East Bay lines, as shown in Figure 45, where the different dark graduation visually highlights the load level of the AC transmission system, before and after the placement of the HVDC link.

FIGURE 45: GREATER BAY AREA TRANSMISSION SYSTEM LOADING CONDITIONS WITH AND WITHOUT HVDC LINK IN OPERATION



Source: SIEMENS, 2013, (17)

E. Identification of Viable Solutions for the Vietnamese Transmission Network

E.1 Key Points Summary of solutions identification

Vietnam is experiencing rapid growth in consumption and a commensurate expansion and evolution of their energy transmission network. This means that its Smart Grid roadmap will need to be refined to include applications that are not yet integrated within their existing systems.

Therefore, a gap analysis has been performed in order to identify all the applications not yet integrated in the existing grid but which are fundamental to reach an adequate technological level in the transmission system for enabling a Smart Grid development. This analysis has been carried out starting with those identified issues and challenges in conjunction with including the functionalities that a transmission utility should have installed. The aim is to have a target operating model in line with the common current technologies and functionalities developed in most of the world's power systems.

With this approach in mind it is possible to position Vietnam on a timeline that highlights the technological gap that its transmission system has to span between its current operating model and the target operating model, as shown in Figure 46.

This phase can be considered as a "**transmission system enhancement**" and the following initiatives have been identified as basic building blocks:

a. **Planning and AMS basic strategies improvements**: The aim is to drive transmission network expansion in order to overcome present network topology issues;

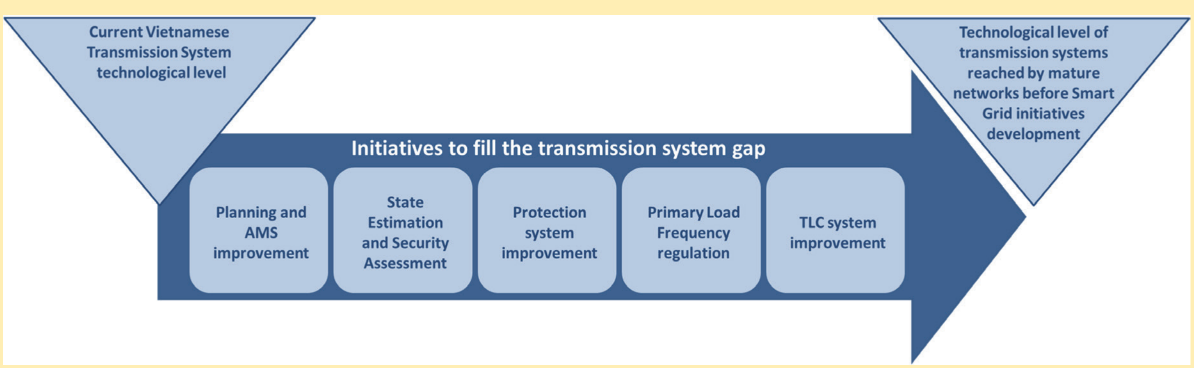
b. **State Estimation and on-line N-1 Security Assessment**: The aim is to have proposed on-line solutions for expected contingencies; improve the real time knowledge of electrical system status and recommend best practice in preventive and corrective remedial actions;

c. **Load-Frequency Regulation strategies improvements**: The aim is to guarantee frequency stability and transient support by allocating sufficient primary reserve to overcome any power imbalance due to generation tripping or changes in the imported/exported power levels;

d. **Protections System improvements**: The aim is to equip substations and transmission lines with state of the art digital relays in order to protect against failures and coordinate their intervention by means of inter-tripping logic systems (when required);

e. **TLC system improvements:** The aim is to support the development of the initiatives listed above. NPT's current data communications network project should be complemented in order to enhance the development of the above applications.

FIGURE 46: TECHNOLOGICAL GAP THAT VIETNAMESE TRANSMISSION SYSTEM HAS TO FILL



Source: Authors

This chapter includes the following:

a. A brief overview of the Vietnamese issues and challenges, fully described in 'Annex 2b';

b. A description of basic building blocks (named "pillars") just mentioned, using best practices as articulated in the section on international experiences;

c. A table of those Smart Grid initiatives identified as viable for Vietnam. In particular, this section aims to map the issues and challenges to the "pillars", described in paragraph 'E.3', and to the Smart Grid solutions that will be described in the following chapter 'F'.

E.2 Overview of Vietnamese issues and challenges

As stated in the previous paragraph 'E.1', developing nations like Vietnam require a "**transmission system enhancement**" phase before implementing Smart Grid initiatives to ensure that the future transmission network is built on a solid enabling foundation.

The survey of international experiences has collected best practices for the enhancement of transmission systems to provide a sound base for the development of Smart Grid initiatives.

This chapter aims to identify all the proposed solutions for the Vietnamese transmission network linking each to the particular issue being addressed.

Transmission system enhancement initiatives will be described in paragraph 'E.3', while chapter 'F' is dedicated to Smart Grid Solutions.

Firstly, it is worth summarizing all the issues and challenges identified in the Vietnamese Transmission System (also confer 'Annex 2b'). Those will be used to introduce the solutions described in the following chapter 'F'. The list of issues highlighted includes:

a. Network topology issues;

b. Short Circuit Level;

c. Miscoordination of Protection System;

d. Defense Plan improvements;

e. Load-Frequency regulation;

f. 500kV limited transient stability;

g. Voltage Stability, Profile and Support/Reactive Power Balance;

h. Lightning Performance of exposed 220 kV lines;

i. SCADA & Remote Control Centers;

j. Time and cost reduction of asset maintenance;

k. Power Quality; and

l. Interconnections with neighboring countries.

E.3 Transmission System enhancement: pillars for building a Smart Grid

The Gap Analysis identified some functionalities and concepts that NPT and/or NLDC has to implement in the very short-term. These can be considered as the "**pillars**" for building a Smart Grid. This idea will be used again in the design of the "**technical prioritization analysis**" of Smart Grid initiatives, described in chapter 'G'.

In this section these concepts will be described briefly, using best practices as articulated in the international experiences section in order to tailor some initiatives for the Vietnamese context.

A paragraph will be dedicated to each pillar, except for "**TLC system improvements**" which will not be directly investigated. In fact it cannot be considered as a single initiative, but only as a key enabling feature of an existing system to support other application development. If the Vietnamese TLC system, in its present state or in the near future, is or will be adequate to support the implementation and/or enhancement of initiatives like state estimation or primary load-frequency regulation, then no further action will be required.

In this chapter the description of functional and organizational structure models of Transmission Utilities, as described in 'Annex 1' will be referenced to indicate the functions that are required to develop each application and the eventual interactions between them.

E.3.1 Planning and Asset Management System basic strategies improvements

In order to increase the resilience of the power system given the present network topology issues such as meshed HV networks and high level of short circuit values it is appropriate to adopt some simple solutions involving Planning, Asset Management and System Operation functions.

First, from the analysis of the single line diagram of the Vietnamese system and from the information received from NPT technicians it is clear that all of the 500/220kV interconnections autotransformers are devices with a delta tertiary compensation winding where the main winding neutral is grounded. This reduces the single phase short circuit voltage drop, bounds the zero sequence fault current to the faulted section but increases its amplitude.

With the aim of reducing the single-phase-to-ground short circuit current in those cases where three auto-transformers are installed in the same station, suitable local automation systems could be implemented in order to keep two of them with neutral grounded, while the third one remains ungrounded. This provision requires the installation of suitable breakers in between the neutral of the autotransformers and ground.

The Vietnamese network topology could lead to a very high fault current that could exceed the rated current thresholds of their circuit breakers causing failures when opening. For this reason the bus-bars of some stations are operated separately resulting in a lower reliability of the system contrary to the N-1 criteria. This happens on the 220kV network where most circuit breakers have a rating capable of withstanding currents of 40kA. This limit is not particularly high as nowadays typical breakers installed in 220-230kV networks around the world have rated current thresholds of 50kA, or more. So, if the short circuit level measured in most critical areas of the network is less than the rated current thresholds of newer breakers, this may present the opportunity of swapping the breakers as described in the international experience (see D.2.2). This solution is applicable to openair substations or hybrid ones. It cannot be applied to Gas Insulated Switchgear (GIS).

Substitutions of breakers and small changes to the mechanical provisions for busbars and bays could enhance their resilience to dynamic stresses caused by short circuit currents. These provisions should be closely studied and designed, but this technique has been successfully applied in a number of substations across Italy. Note that very often busbars and bays are already over designed from the point of view of mechanical resilience and thus these additional provisions are simple and cheap. Terna conducted some studies of the network and successfully tested these provisions.

In the long term, with the installation of renewable power generators (wind and solar) the higher levels of short circuit power relative to the increase of the total power throughput becomes less critical since renewable power generators (based on, or connected through, power electronics) provide a negligible short circuit power contribution.

The Vietnamese transmission network also has some reactors between busbars (acting as bus couplers) and the devices and associated equipment (the reactor itself, breakers, etc.) could be installed to solve some specific issues related to the short circuit currents exceeding the threshold of the equipment. Such reactors can be equipped with a bypass breaker in order to switch it on or off depending on the dispatching condition of the system (i.e. short circuit power and load flow). It is worth considering that switching such reactors on or off through the bypass breaker could be controlled remotely or even automatically, depending on the state of the station bay breakers.

Finally, since single pole reclosing is being used, an analysis of the operation statistics could lead to the identification of those overhead lines with many successful instances of single pole reclosing. These lines should be carefully considered for the application of the LSA. Furthermore the best location for LSAs can be decided on the basis of analyzing distance relay records for the incidence of faults.

On the other hand, if a high percentage of unsuccessful single pole reclosing occurs, it could be a symptom of a non-optimal selection of the neutral reactance associated with the line side shunt reactors.

E.3.2 State Estimation and N-1 Security Assessment

The first enhancement to NTP's network operation is the roll-out of a State Estimation and a modern state-of-the-art Energy Management System. NTP has undertaken the modernization of their SCADA/EMS systems in all the four Control Centers. The new system will meet the requirements addressed in this report and the findings from the analysis of the recent incidents that occurred in the Vietnamese Power System.

After the roll-out of the State Estimation algorithm, an on-line Security Assessment Procedure should be implemented. The procedure should be automated in order to avoid Operator intervention in collecting and preparing data, running the simulations or collecting and analyzing the results. The procedure should start by automatically collecting the most recent state estimation output, evaluating system response against a list of significant and credible contingencies and, finally, presenting the results to an operator-oriented interface.

Since transient instabilities have been detected on the 500 kV backbones, a dynamic security simulation of the power system should be included in the Security Assessment Procedure. The most credible triggering events, such as breaker failures or 500 kV circuit tripping, could be repeatedly simulated on every new SE snapshot to ensure the system's ability to withstand the transients caused by the contingencies/triggering events.

The Operator will be able to change the operation of the system from the optimized configuration to a secure one. This action should be based on the results and the guidance of the on-line security assessment.

The most updated power system models, from a steady state and dynamic point of view, should always be provided for the Security Procedure. Thus, the SCADA/EMS will allow the users to upload the models into the Security Assessment procedure with no significant restrictions.

The on-going new SCADA / EMS project (see paragraph 'F.2') will deploy a modern Energy Management System which has an integrated Security Assessment feature. Thus the procedures should be accurately tuned in order to meet the simulation requirements above.

E.3.3 Load-Frequency Regulation strategies improvements

The first step is to analyze the primary load-frequency regulation of the system based on the best set of hydropower units that contribute to this type of regulation by selecting the best drop for each one. After this initial phase the performance of the overall EVN system in terms of eventual inter-area power oscillations should be monitored.

The remedies, if needed, consist of reconfiguring the primary load-frequency regulation (set of regulating power units and selection of their drops) followed by the secondary frequency regulation.

According to international best practices, the largest number of the generators connected to the grid should participate in the Primary Load-Frequency regulation. This is the best approach to achieving a good primary regulation. An exception to this prescription may be issued for small generators, e.g. with rated power below the value determined according to the size of Vietnamese power system, which could not guarantee the necessary performance for the primary frequency control or the suitable amount of primary reserve.

Additionally, a suitable Automatic Generation Control (AGC) for secondary regulation should also be installed.

In order to create optimal primary and secondary regulation, studies and simulations must be conducted in order to fine-tune the dynamic models to align them with the records of frequency and the responses of the Vietnamese system.

E.3.4 Protections System improvement

NPT's current initiatives regarding the definition of basic specifications for protection and control systems being installed in their new stations combined with the adoption of advanced IED together represent a step towards system improvement and will help to resolve the problem of a miscoordination of the protection system (described in 'Annex 2b.viii').

In the event that it proves to be insufficient, a detailed survey of all installed protection systems, especially in older stations is highly recommended. In this way, it will be possible to characterize and categorize all the installed protection systems, highlighting the eventual causes of their malfunctioning or miscoordination and facilitate the development of an effective intervention policy to either repair or replace.

Therefore, to reduce transmission network vulnerability to faults, as stated for Asset Management and Planning in paragraph 'E.3.1', it is important to assess both new components that have to be installed as well existing ones. In fact, putting together all the critical nodes of the network (i.e. old and new installed stations) it will be possible to list the real categorizations of the problems experienced with protection systems and of devices where there is a greater need for remedial intervention.

Furthermore, it is possible to improve the requirements of the protection system by developing an installation strategy that will support consistent and incremental improvement of system reliability. For example it may be appropriate to copy successful strategies used in developed countries by installing two completely independent protection systems at each end of a line, operating with different algorithms and provided by different vendors. Both these devices would be completely independent of each other at both the hardware (e.g. cabling, case, etc.) and software (e.g. programming, algorithms, etc.) levels and it would be enough if only one of them triggered the start of the protection logic.

The cost of testing and proving two different devices for the same function is an expensive proposition but not nearly as costly as the damaging effects of protection system malfunctions or miscoordinations on the whole transmission network.

E.4 Problems-solutions mapping

Before providing a detailed description of individual Smart Grid initiatives, it is important to introduce them in connection with the problems they are intended to resolve and to plan their development over a realistic time frame. Table 13 and Table 14 aim to map the issues and challenges to the "pillars", described in the previous paragraph, and to the Smart Grid solutions that will be described in the following chapter 'F'. In some cases the simple "pillar" implementation is required while in others only a Smart Grid initiative can solve the problem.

The aim of each solution is to solve the associated problem and will be described in the following chapter 'F' and, as can be seen from both Table 13 and Table 14 that some solutions solve more than one problem.

Over the lifetime of all the projects across the three time scales the complete integration of the solutions within the transmission system, properly leveraged (especially WAMS or SAS) could address a much wider set of issues.

Using WAMS as an example of this approach; the installation of PMUs at key points of the transmission network could facilitate, in the medium/long term, the development of Defense Plans based on early warnings based on WAMS measurement. This would be possible only after a full integration of WAMS with the transmission

TABLE 13: ISSUES-SOLUTIONS MAPPING

ISSUES	ISSUES CHARACTERISTICS	PILLARS	SMART GRID SOLUTIONS
Network topology issues	• Network highly meshed	• Planning and Asset Management strategies improvements	• Static Var Compensators • Dynamic Thermal Line Rating
Short Circuit Level	• Fault current could exceed the • rated current of the breakers	• Planning and Asset Management strategies improvements	• Not Applicable
Miscoordination of Protection System	• Outages due to protections failures • Interference and electro-magnetic compatibility issues on secondary signals	• Protection System improvement	• Power quality monitoring system
Defense Plan improvements	• If the N-1 security criterion is not fulfilled an SPS remedial action is necessary • The security assessment is performed off-line not on-line	• State Estimation • N-1 on-line Security assessment	• Substation Automation System • Wide Area Monitoring Systems
Load-Frequency regulation	• At present this type of regulation is achieved by using only one of five single hydro power plant at a time	• Load-Frequency regulation strategies improvements (AGC)	• Not Applicable
500kV limited transient stability	• High North–South power flow	• State Estimation • N-1 on-line Security assessment	• Wide Area Monitoring Systems
Voltage Stability, Profile and Support/Reactive Power Balance	• High North–South power flow	• State Estimation • N-1 on-line Security assessment	• Wide Area Monitoring Systems • Static Var Compensators
Lightning Performance of exposed lines	• Surge Line Arrester installation without a Lightning Location System	• Not Applicable	• Lightning Location System

Source: Authors

TABLE 14: CHALLENGE-SOLUTIONS MAPPING

CHALLENGES	CHALLENGES CHARACTERISTICS	PILLARS	SMART GRID SOLUTIONS
Monitoring and remotely control the network	• Improve the monitoring, observability and control of the network	• Telecommunication system improvements	• Substation Automation System • Wide Area Monitoring Systems • Metering Data Acquisition System • Geographic Information Systems • On-line Dissolved Gasinoil Analysis for Power Transformers
Time and cost reduction of asset maintenance	• Improve the efficiency of the system	• Not Applicable	• Fault Locator System
Power Quality	• Improve the quality of the system	• Not Applicable	• Power quality monitoring system
Interconnections	• Interconnections with neighboring countries	• State Estimation • N-1 on-line Security assessment • Load-Frequency regulation strategies improvements	• High Voltage Direct Current technology

Source: Authors

operation system as well as the System Operation staff acquiring a complete understanding of this technology.

Therefore, Table 13 and Table 14 are very useful for providing a basic introduction to all the solutions and to map the initiatives with the specific Vietnamese transmission system problems they aim to solve. Their positioning within the different time horizons will be investigated in the “**technical prioritization analysis”** of Smart Grid initiatives (see chapter ‘G’), after a full description of the possible developments and benefits of each initiative, which will be performed in the following chapter ‘F’.

F. Description of Smart Solutions Identified

F.1 Key Points Summary of Smart Grid Solutions

Vietnam has already undertaken some steps towards the development of Smart Grid technology across their infrastructure. In particular in March 2012 ERAV, the Electricity Regulatory Authority of Vietnam, promoted and developed a "Smart Grid Project and Implementation Roadmap" officially approved in November 2012 (decision n° 1670/2012/QD-TTg). The roadmap consists of three phases (short, medium and long-term) and covers both the transmission and distribution networks.

In January 2013 the Minister of MOIT established the Smart Grid development Steering Committee at which 15 members from the different companies involved in the electrical sector regularly meet.

The Smart Grid projects for the Vietnamese transmission network sit under the umbrella of "Decision n° 1670/2012/QD-TTg". According to the classification assigned by the Steering Committee, some initiatives are included in the first phase of the Smart Grid roadmap (short-term) and will function partly as pilot projects while the full deployment of the solutions will have a medium-term perspective.

Thus, it is worth recapping the Smart Grid applications already in progress or planned for the Vietnam Power Transmission Network:

a. At the time of writing this report the following are in progress:
    i. Substation Automation System;
    ii. Information System for Operation and Supervision; and
    iii. Wide Area Monitoring Systems (WAMS)—Pilot project.
b. Roadmap:
    i. Substation Automation System upgrade;
    ii. Communications Infrastructure for Transmission and Substations;
    iii. Upgrade Information System;
    iv. Metering Data Acquisition System;
    v. Wide Area Monitoring Systems (WAMS);
    vi. Dynamic Thermal Circuit Rating (DTCR);
    vii. Fault locator system (FLS); and
    viii. Geographic Information Systems (GIS).

The aim of this chapter is to describe all the Smart Grid solutions identified in paragraph 'E.4' and for each one to point out if;

a. A similar solution has been already proposed by the existing Vietnamese Smart Grid roadmap. If this is the case then the Vietnamese solution will be briefly described; and
b. It is a new opportunity in which case the proposed solution will be based on international best practices as previously described.

Therefore, this chapter summarizes the technical sections of the proposals for the Vietnamese transmission network and is aimed at commercial and business level decision makers. The first two sections provide a brief description of the enhancements to the SCADA / EMS system and the telecommunications infrastructure for the transmission grid. These are necessary pre-requisites for the development of a reliable and efficient electrical transmission system and, as such, are outside the scope of a typical Smart Grid roadmap.

This is followed by a presentation of the Smart Grid initiatives proposed for the Vietnamese transmission network and includes the following:

a. **Substation Automation System (SAS)**: This section describes the NPT project already underway and makes recommendations to optimize the benefits of this solution especially with regard to interoperability and telecommunication system improvements.
b. **Wide Area Monitoring System (WAMS)**: The main focuses are:
    i. The PMU positioning strategy emphasizing the importance of monitoring not only the 500 kV network but also the 220kV network;
    ii. The brief description of possible WAMS applications useful for the Vietnamese context

such as voltage stability monitoring, oscillation detection as well as monitoring.

c. **Lightning Location System**: This presents a guideline for the development of this system highlighting the benefits with a particular focus on the installation of Transmission Surge Line Arresters.

d. **Static Var Compensator**: The main benefits of this type of system are identified with reference to possible applications within the Vietnamese transmission grid. The installation of the SVC systems is recommended in order to better regulate the voltage profile of the 500 kV transmission lines and, with suitable control loops properly integrated with the WAMS applications, to significantly increase the damping of the system during transients particularly in cases of inter-area oscillation. The use of re-locatable SVC systems is recommended as a possible solution to ensure the maximum flexibility for this kind of application in the light of the rapid development of the transmission system and the need to provide timely, location specific support for substantial changes and re-configurations of the grid.

e. **High Voltage Direct Current technology**: The main benefits of this technology are presented, highlighting the possible fields of application from a long-term perspective. The technical and economic benefits that can be achieved are discussed for some specific applications, such as the interconnection with neighboring countries and the supply of large congested loading areas with high levels of short circuit currents and loop-flow issues.

f. **Fault Locator System**: The main benefits of this technology are investigated in the context of asset maintenance in order to deliver significant time and cost efficiencies.

g. **Power quality monitoring system**: The benefit of this type of system is analyzed primarily in terms of improving power quality levels which helps to optimize investments in installations aimed at increasing resilience to voltage dips and increasing the ability to promptly identify malfunctioning protection systems.

h. **On-line Dissolved Gas-in-oil Analysis (DGA)**: The main benefits of such technology are presented with recommendations to equip all new transformers with this type of device. Their use with the existing transformer fleet will require the identification of the most critical and valuable ones that need to be protected.

i. **Dynamic Thermal Circuit Rating (DTCR):** The main techniques used for implementing this solution are presented. The steps required to develop a DTCR project that uses all the different techniques are also proposed.

j. **Geographic Information Systems**: This cannot be considered as a single Smart Grid initiative in its own right but needs to be seen as a means of enhancing other applications. Its benefits will impact different Transmission Utility functions, like System Operation and Asset Management.

k. **Metering Data Acquisition System**: Before commencing an initiative to acquire meter data remotely it is important to carefully consider the regulatory implications and aspects and to develop an appropriate protocol for the interface with the electricity generation function in the event of critical situations. This application represents an enabling technology for the development of the electricity market.

For the various initiatives different levels of detail will be assigned, depending on their complexity, the criticality of the problems they aim to solve, the existence or not of a Vietnamese project that will need analysis and the state of development of the project itself as well as the areas in which it can be exploited. In particular, the applications that may have a wide ranging and positive impact on the transmission system will be significantly detailed.

Finally, in chapter 'G' each solution will be located on a technology driven timeline, specifying whether it is a short, medium or long term initiative and, if necessary, indicating the prerequisite steps prior to starting it. In this way it will be possible to design a realistically phased Smart Grid roadmap.

F.2 New SCADA/EMS system

Before starting a detailed analysis of the proposed Smart Grid solutions it is useful to briefly describe the on-going project of the SCADA/EMS implementation. This system, in fact, will be the focal point for all the Smart Grid applications and will be the point of interaction and information exchange, both for acquiring data and providing results.

The purpose of this project is to implement a hierarchical SCADA/EMS system comprised of a set of fully integrated, geographically distributed and redundant Supervisory and Control Systems to support the National Load Dispatching Center in the operation of the country-wide bulk interconnected Electricity Power System. The

SCADA/EMS will have four different sites, including the National Load Dispatch Centre (NLDC) and the Northern Regional Load Dispatch Center (NRLDC) which are both in Hanoi, the Central Regional Load Dispatch Center (CRLDC) in Da Nang and the Southern Regional Load Dispatch Center (SRLDC) in Ho Chi Minh City.

The new SCADA/EMS system will include several functions, amongst which are:

a. A Graphical User Interface (GUI);

b. A situational awareness system;

c. An advanced alarm management system;

d. A real-time and historical trending application;

e. A load shedding and restoration system;

f. Automatic generation control and dispatch modules;

g. Short-term load forecasting;

h. Market operations interfaces;

i. Tools for network security analysis;

j. Dynamic security assessment;

k. Voltage stability and transient stability analysis; and

l. An operator training simulator.

NLDC plans to conclude this project in 2015.

Even though some functions can be considered basic for mature and highly interconnected networks, a SCADA/EMS system at the National Load Dispatching Centre certainly represents a pre-requisite for the development of a reliable and efficient electricity transmission system. Therefore it must be considered as one of the first steps in the Smart Grid roadmap for the fast growing and developing country of Vietnam.

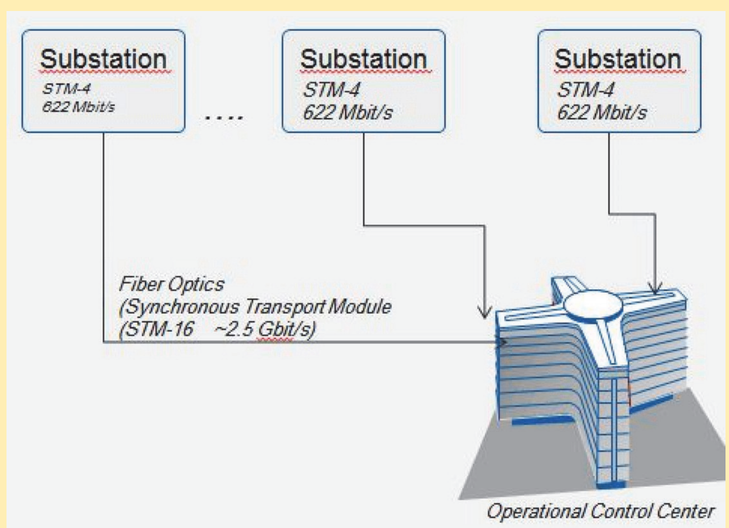
For the development of the Smart Grid roadmap it is also worth to consider that NPT is currently building a technical management software (management device parameters, line, reporting, monitoring equipment, laboratory ...). This initiative aims to increase power system operational efficiency focusing on solutions for unmanned substations management and operation, remote control and switching centers. This software provides users with simultaneous access to a large amount of real-time information and historical data. All of these data are collected, achieved, and maintained, always ready for operation, planning, and maintenance activities as well as large-scale applications. Therefore, such initiative plays a fundamental role in supporting and exploiting Smart Grid solutions described in the following paragraphs.

F.3 Telecommunications Infrastructure for the Transmission Grid

In order to collect the data to be used in the new SCADA/EMS system (NLDC), as well as to support remote control of the substations of the electrical network (NPT), the development of a communication backbone connecting all the substations under NPT management is a fundamental requirement. The total expected investment is about USD 2,000,000 and includes the equipment to interface with STM-4 (622 Mbps) communication links. A quick sketch of the tentative solution is presented in Figure 47.

Even though a telecommunications infrastructure is not usually considered part of a Smart Grid program in mature and highly interconnected networks since it is usually already installed as a backbone system, it is a pivotal enabling technology for the development of a reliable and efficient electrical system. Therefore the current data communication infrastructure initiative can be considered as one of the steps in the Smart Grid roadmap for a fast growing and developing country like Vietnam.

FIGURE 47: NEW TELECOMMUNICATION INFRASTRUCTURE



Source: Authors

The main purposes of this upgrade project of the Information System are:

a. To **connect directly to NPT's substations** for acquiring data (Analog, Status information at the **substations** and metering data) and providing data to PTC's Information Systems and data backup for NLDC's SCADA system;

b. Integrating **WAMS**, **DTCR**, **FLS** in NPT's and PTC's Information Systems;

c. Integrating **advanced functions** such as load flow, stability limit, transfer capability of transmission network in real-time (on-line), fault, off-line stability, etc.;

d. Exchanging information and data with other parts of the system in Vietnam's **Electricity Market**; and

e. Allowing the registered users of NPT and PTC to easily access necessary information from anywhere using Web services with a **high security level** in accordance with **international data security standards**.

These objectives highlight just how pivotal the Information System is as the load-bearing structure of all the Smart Grid initiatives that are required for the Vietnamese system and that will be described in the following sections. In this report the design of the new IT system will be assumed to be consistent with a modern IT system, both in terms of having a fully enmeshed and resilient data communication capability complete with services for storing and processing data and the ability to support all the Smart Grid applications as required. For those initiatives that have a particular impact on pre-existing IT systems (like Automation and Tele-Control for Substations or WAMS) special needs will be underlined or the specific necessary structures and devices will be described.

Before starting with a description of Smart Grid initiatives, it is worth focusing on a specific path for improving the data telecommunication systems in the context of a Wide Area Network for Market Development.

F.3.1 Wide Area Network for Market Development

The construction of a Wide Area telecommunication network for connecting all the players that participate in the electrical market is seen as a discrete standalone project in Vietnam.

It differs from the telecommunication network currently being implemented for the exchange of information between the transmission substations and NLDC/NPT control centers, as the former will connect customers and generation plants outside the EVN boundary.

The project has not yet been started and at present no deadlines have been agreed for its completion. However, NLDC considers the project of the greatest importance and is pushing for a quick approval. The infrastructure will be based on an optical fiber backbone.

It is likely that the new telecommunication network will be used for enabling different markets including the ancillary services where considerable improvements can be made. In fact the actual management of primary and secondary network energy reserves must be improved and fine-tuned.

As already stated regarding the primary telecommunication infrastructure for NPT's transmission grid, the new Wide Area telecom network itself cannot be considered part of a Smart Grid program in a mature and open energy market but it is an essential enabling technology for developing an integrated Smart Grid in Vietnam.

The problem of connecting players outside the EVN boundary will be described in paragraph 'F.14', where the Metering Data Acquisition System initiative will be investigated. As discussed in the international experience section (see D.2.9) on metering, the requirement of measurability is the basic condition and indeed a key performance indicator for the admission of each power plant to the electricity market.

F.4 Substation Automation System

Fully digitized substations, remote terminal units, remote operations and supervision are basic functionalities of a modern power transmission network and they are the pre-requisites for further developments towards a Smart Grid. Towards this aim Vietnam is implementing an initiative to modernize the 220 and 500 kV electrical substations of the transmission network. The project has been in place since 1999 and is now in its third phase and its main characteristics will be described in the next section (F 4.1 below).

F.4.1 NPT Substation modernization initiative

In the first phase NPT had to deal with:

a. Digital protection and control using legacy serial and hardwired connections;

b. Problems with interoperability between multiple manufacturers' IEDs.

In the second phase which was started in 2003 EVN issued a specification for SAS aimed at improving IED compatibility. UCA2, Modbus TCP, DNP TCP, and IEC 60870-5-104 were chosen as substation LAN communication protocols between Host Computers and IEDs or NIM (Network Interface Modules). The IEC 60870-5-101 protocol was chosen to move data from a substation's realtime database to the existing SCADA system.

The currently ongoing third stage will see the installation of digital equipment and the adoption of the IEC 61850 protocol for LAN communications. The IEC 60870-5-101/104 will be used instead for communication between the Substation Automation Systems (SAS) and the Remote Centre, i.e. the Information System for Operation and Supervision of NPT networks.

The project will oversee the construction of 236 new substations and the upgrading/revamping of another 183. The Information Centre will support remote operation of the substations and the first instance of remote operations capability will be in place by the end of 2015.

NLDC's SCADA/EMS System and NPT's Information System will collect information in parallel from the field and will be able to exchange data by means of a direct link using ICCP protocol as shown in Figure 48.

The protocol IEC 60870-5-101 has been chosen for its compatibility with legacy systems and supports the integration of the SAS of the old substations as they cannot currently support IEC 60870-5-104 (the newer and more flexible protocol). In the deployment of the SAS project it is important to install RTUs that support a dual configuration capable of supporting both IEC 60870-5-101 and IEC 60870-5-104. This will be a useful starting point for possible future developments as it will allow a full migration to the IEC 60870-5-104 protocol for all substations.

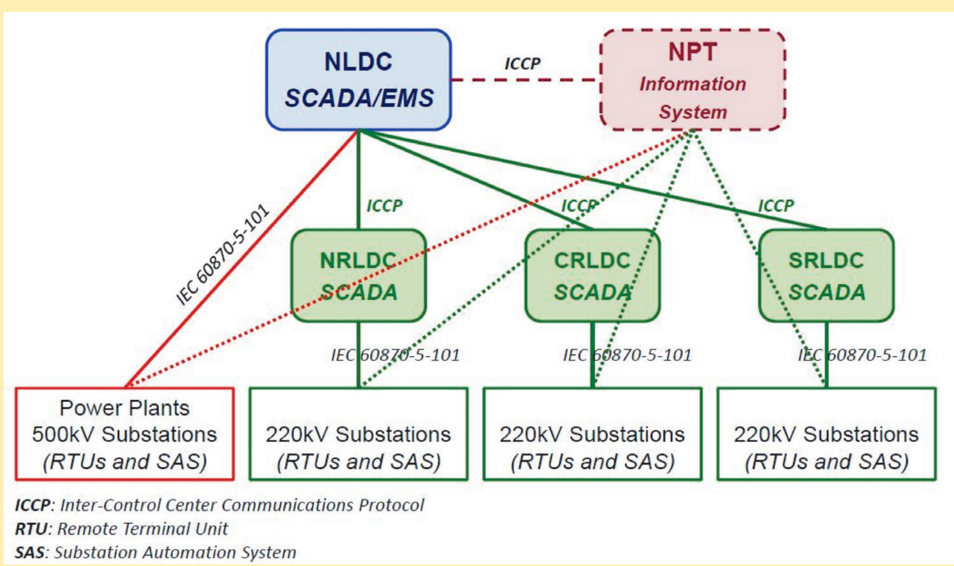
This NPT project is basically comprised by two interventions:

a. Substations' modernization process (upgrade of old substations and building of a wide number of new ones);

b. Building of Remote Control Centers for unmanned substations.

The expected benefits of this system concern different aspects and they will be fully achievable if the substations' modernization process will be conducted in synergy with building of Remote Control Centers for unmanned substation. Remote Control Centers, in fact, constitute a prerequisite to exploit at best SAS equipment in electrical substations.

FIGURE 48: NEW NLDC SCADA/EMS AND NPT INFORMATION SYSTEM



Source: NPT-World Bank, 2013, (18)

Looking to SAS benefits, this system substitutes physical displays for Substation Online Metering and Alarm with easy to understand and operate HMI in terms of:

a. Alarm Annunciation;

b. Trending;

c. Substation Logs; and

d. Display Generation and Maintenance.

The last point to be considered and perhaps the most challenging is the development of a flexible HMI capable of supporting display configuration as this will require significant investment and effort.

Furthermore, the SAS Historical Information System (HIS) will be provided to store any data item at 1 second intervals and to maintain the entire data set on the hard disk, for real-time on-line access, for a period of at least 2 years.

Finally, the SAS implementation is assumed to lead to:

a. Faster system integration with IED interoperability;

b. Reduction of copper cabling and hardwiring (all control and protection cubicles will be installed in outdoor cubicles and /or bay housings);

   i. GOOSE for peer-to-peer data exchange; and

   ii. Outdoor cubicles adjacent to feeder or bay.

c. Reduction of system malfunctions by nearly 50%.

Whilst the last point above suggests that system malfunctions will be reduced simply by deploying SAS, it is not completely correct. In fact, the larger the number of devices and components installed the greater the likelihood of failure somewhere in the chain and this fact must be given due consideration. It is probably more accurate to say that the implementation of SAS will significantly reduce fault finding times thus decreasing the mean time to repair.

Among all the Smart Grid initiatives SAS is definitely the one whose implementation has reached the most advanced stage. The choices made, in terms of technologies and development strategies, and the anticipated benefits compare favorably with international best practices (see D.2.6). However, it is worth taking account of the key points to be monitored in the SAS project development process in order to ensure a successful deployment and to apply a continuous improvement strategy for the lifetime of the project.

F.4.2 Recommendations for continuous improvement strategy

The outcomes of the second phase are the basis for achieving communication interoperability. The aim is to have seamless communication within the power system based on an open communication protocol not only between the IEDs but also for inter-substation communication and on the link between substations and control centers.

The activity of interoperability testing and standards analysis has to continue during the whole implementation process as well as into the future. Future developments need to remain mindful of the risk of proprietary lock-in if there is an over reliance on a single vendor or standard. This could happen when system upgrades involve high costs due either to commercial or technical constraints.

To minimize such risks, recommendations for upgrades and future developments must be unambiguously based on best practices and offer the most flexible, open standard architecture as well as effective risk mitigation strategies. These recommendations should provide a direct path for the simple definition of future projects, thus avoiding the most common "tricks and traps" and other lock-in mechanisms used by manufacturers to reduce a customers' freedom of choice.

Moreover, from a technical point of view, each upgrade must be evaluated on the basis of not only the target device but also in terms of the impact that this action has on all the other devices and systems connected to the target device i.e. in a word, interoperability.

Thus, amongst other topics, the correct alignment of devices for NPT's needs and goals will be a key factor of success. For this reason it is crucial to evaluate the features of any proposed systems, devices or equipment especially in terms of:

a. Open standards;

b. Performance adequacy;

c. Feasibility of upgrades;

d. Worldwide presence; and

e. Vendor support.

F.4.3 Telecommunication system improvement

Another fundamental aspect of the SAS project is the telecommunication system improvement that may be required for an extensive deployment of this application. Different levels of implementation of a SAS project imply increasing investments in the telecommunication system. It is possible to identify four levels of telecommunication system development related to correspondingly more complex levels of SAS project deployment:

a. **Remote control (alarming)**: Which entails the lowest level of performance required of the telecommunication system;

b. **Remote monitoring (components diagnostics)**: Here the telecommunication system has to support a larger data stream due to the exchange of all the measures necessary for real-time substation monitoring;

c. **Communication between substations**: In this case the meshing and resilience required of the telecommunication system is more demanding;

d. **Monitoring of renewable generation**: This is the last step in a SAS project and requires an additional layer of interconnectedness of the telecommunication network. This development will be useful for different aims like communications of real-time forecasts, remote control of wind generation, etc.

As stated before, one of the goals of the SAS implementation is the adoption of GOOSE for peer-to-peer data exchange. This means that the project in Vietnam will require the third level of telecommunication systems improvement development as per the list above, i.e. item (c). Before doing this it is important to be certain of having achieved communications between all the substations and the control center both for control and monitoring.

Moreover, before deciding the level of meshing required of the telecommunication system to support GOOSE, it is fundamental to decide the types of plans (i.e.: defense plans, load shedding, generation shedding, etc.) NPT and NLDC want to manage with this application and which substations will be involved. This approach will be useful in dictating the improvements to the telecommunication system in those areas likely to be affected by this type of application, thus concentrating investment only on critical nodes of the network.

The Vietnamese case differs from those situations with some transmission systems (discussed earlier in D.2.6), where it was decided to communicate with the control center to exploit the existing TLC network and therefore to use GOOSE only for intra-substation communications.

The Vietnamese case involves a significant number of completely new devices. Thus, it is not worth limiting the performance and flexibility of the system by accepting the constraints imposed by current and legacy technology. Instead the installation of new substations and the development of the TLC system should be viewed as an opportunity to deliver a high technical standard of data communications for GOOSE deployment.

The communication between substations is a significant opportunity to develop advanced plans for system operation, especially for emergency situations. The use of GOOSE and therefore a lower requirement to exchange information with the control center, could allow the development of more flexible system operation plans. For example the designs and strategies for restoration the communication between substations could include fewer constraints regarding selected paths thus facilitating faster and more reliable recovery strategies.

Therefore, in the SAS project the development of GOOSE might be one of those Smart Grid applications for coordinating the development of the different roles of the transmission in an efficient way. System operation has to investigate those functions that could exploit communication between substations. The planning has to accommodate an appropriate telecommunication system enhancement in order to support such functions and ultimately asset management has to deal with the installation of all the required devices.

Equally, it is important to underline that the creation of a highly resilient and reliable communication infrastructure between devices using GOOSE is really challenging. This requires special attention on creating the communication architecture at the beginning of the project and involves a dedicated network design phase for the selection of the network components, Ethernet interfaces and the IEDs themselves. Moreover, extensive interoperability tests are needed to ensure devices from multiple vendors work together smoothly.

Finally, the SAS project could be upgraded to include the monitoring of renewable/distributed generation. This upgrade not only represents another level of complexity in the development of the telecommunication systems but also poses the technical challenge of achieving data-exchange between the target devices and the distribution network, where most of the renewable/distributed generation systems are connected. This issue could also be faced by the Metering Data Acquisition System, described in F.14, where again the interface is between the transmission and distribution network.

F.5 Wide Area Monitoring System

The main cause of wide-area disruptions in the present NPT network is due to the relatively long 500 kV transmission line between Hoa Binh and Ho Chi Minh City, which is susceptible to voltage and angle instabilities when there are variances in load and generation sources.

Synchrophasor technology provides observability of the status of the power system to operators in real time, which facilitates the calculation of the maximum loading condition for each system bus connected to the transmission network. Furthermore, preplanned corrective actions can be taken to minimize the risk of wide-area disruptions and increase the power transfer capability of the system. The availability of a high-speed, high-bandwidth network architecture makes synchrophasors ideal for this application.

F.5.1 NPT pilot project

Towards this end NPT has developed a customized solution for wide-area measurement that uses the synchrophasor functionality within the installed IEDs. In particular the HMI solution consists of several applications implemented for specific uses;

a. **Desktop application** for calculating the real-time power transfer capability of the system and to provide alarming based on thresholds set by the user;

b. **MATLAB application** for migration of synchrophasor data to a programming environment for performing complex calculations;

c. **Web application** that provides access to the data remotely through a secure Internet connection; and

d. **Office application** that provides a data-link interface to the plant information database.

Only a few PMUs have been installed so far and the WAMS project for the entire 500 kV network is currently considered as a project with a mid-term time scale and a projected conclusion sometime in 2022.

The project aim is to install PMUs in all 500kV substations under NPT's management [2] and the expected benefits are;

a. Increased system loading while maintaining adequate stability margins;

b. Improvement of operator response time to system contingencies, such as overload conditions, transmission outages, or generator shutdown;

c. The achievement of advance system knowledge with correlated event reporting and real-time system visualization;

d. The promotion of system-wide data exchange with a standardized synchrophasor data format; and

e. The validation of planning studies to improve system load balance and station optimization.

Over the mid-term time scale these predicted benefits could be achieved by successfully exploiting the WAMS project, which has to cover as much of the transmission network as possible. The NPT's pilot project may be a good starting point to study the best way to develop the WAMS project on a larger scale and in particular to test some functions and applications before deciding to implement them across the system.

Thus, it is important to define a development strategy that could be divided into three main steps;

a. PMU devices selection and their positioning;

b. Communication system improvement; and

c. WAMS applications implementation.

F.5.2 PMU devices selection and their positioning strategy

PMU positioning strategy is fundamental to achieving effective observability of the dynamic behavior of the network. The installation of PMUs in all 500kV substations under NPT's management will greatly improve the ability to monitor the long 500 kV transmission lines in terms of voltage and angle instabilities.

However, to achieve complete system observability it will be necessary to extend the real-time system to the wide-spread 220kV network for which it will be vital to develop a PMU positioning strategy.

To this end, the international experience (see 'D.2.7.1') could serve as a useful benchmark for developing an appropriate PMU positioning strategy. In fact, even if complete system observability may be impossible to achieve, it should be possible to focus successfully on monitoring the most critical portions, i.e. areas subject to specific events (e.g. line trip with possible cascading) or phenomena (e.g. voltage collapse, oscillations) which may jeopardize system stability. This is true not only for the 500kV network but also for the 220kV system.

Before detailing the PMU positioning strategy, it is worth making a few observations on the choice of the models of the device to be installed and the related issues. In order to obtain reliable results from applications that will use PMU data it will be necessary to ensure high module and phase performance, which depends on time synchronization accuracy. So, the first step is to decide the required measurement accuracy and, consequently the appropriate PMU models to be installed. While international experience could once again prove a good reference point, it has to be said that the technology has advanced since then and the latest commercial products offer far more satisfactory yields, especially in terms of synchronization accuracy.

In this phase not only operation and planning but also asset management functions must be involved. This collaboration could make a significant contribution to choosing the right devices to be installed and, above all, it must consider if substitutions of other equipment are necessary. For example, voltage and current transducers have to be very precise so CTs and VTs must have a high accuracy class (possibly 0.2%). So, if CTs and VTs are quite old and/or not very precise, it would be better to verify this first and substitute them, if necessary, before connecting a PMU. Otherwise the data gathered will have a high sampling rate and good synchronization but remain extremely inaccurate in terms of the module and thus prove completely useless for the monitoring and control applications that use them.

Following the decision about the most appropriate device models the next task is to select the best location for the PMUs. One of the best ways to do this is by using heuristic-analytical criteria, in order to maximize the operating value of the measurements.

The operators' experience will be especially helpful in pointing out some heuristic criteria (e.g. proximity to large generating units, known bottlenecks, borders, etc.) that could help determine the most suitable location to install PMU, especially in the 220kV network.

On the other hand the development of an analytical positioning algorithm should also be taken into account as this aims to find the places in which PMU installation could improve observability for event identification, oscillation detection, angle, voltage and frequency stability monitoring.

The first type of analytical criterion is **event-oriented positioning** technique (e.g. flag node criterion) and its aim is to find those bus-bars most affected by any kind of perturbation between power systems, combining sensitivity and selectivity of the monitoring facility.

Another type of analytical criterion is the **phenomenon-oriented positioning** technique which focuses on phenomena affecting specific bus-bars or the system as a whole. In the first case phenomena such as voltage collapse or out-of-step are considered. Since the affected bus-bars are already known, the purpose is to detect those that are worst affected. In the second case affected bus-bars are unknown and must be selected and typical phenomena are network islands or inter-area oscillations. In this technique several different approaches based on dedicated network indices have to be investigated and the results merged. Possible classes of indices are voltage-related, oscillation-related and islanding-related.

F.5.3 Telecommunication system improvement

The telecommunication system is crucial for the development and effectiveness of WAMS. PMUs, in fact, acquire and send data with quite a high sampling rate (e.g. 50 times per second). This data (measurements, time stamp, and the other status information) is formatted according to the IEEE C37.118 standard and continuously transmitted to a central server.

This requires a very high-reliability, high-performance redundant communication (e.g. multiple dedicated links) system compliant with the IEEE standard.

Moreover, all of the data acquired by PMUs must be stored on WAMS servers called Phasor Data Concentrator (PDC). A PDC is responsible for processing streaming time-series data in real-time, making it available for the applications that use them. The number of PDCs to be installed, their locations and design must be accurately planned, taking into account both needs and performance required by the WAMS system, the number of PMUs installed, the measurements required and the structure of the telecommunication system.

Finally, this huge amount of data must be managed in an efficient way and is entirely reliant on the IT system. In particular it has to guarantee fast access to real-time data and to the measurements acquired in the near past (few hours). It is worth storing older data, even if it is only required on a less critical basis both in terms of time to access and the sampling rate. If any alarm management application using PMU data is implemented, it would be appropriate to develop a dedicated storing facility for the events identified by the trigger of alarms in order to allow real-time on line access to them.

F.5.4 WAMS applications implementation

WAMS is a key Smart Grid application because its data provides the basic raw input for a large number of advanced functions serving network operation and control. NPT has already planned to develop advanced synchrophasor applications and functions for wide-area real-time control actions such as undervoltage load shedding of noncritical loads, contingency-based remedial action schemes, automatic generation tripping, switching of shunt capacitors and system islanding detection.

All of them will be extremely useful but there are further applications that can use PMU data to deliver improved monitoring and control of the Vietnamese transmission network. In the main these applications are oscillation detection and monitoring, phase angle monitoring, voltage stability monitoring, event detection and management, alarming, backup and integration for SCADA system.

In the following section the two most significant applications will be described briefly, suggesting possible techniques and implementation strategies to apply as well as underlining their added value.

F.5.4.1 Voltage stability monitoring

'Annex 2b.iii' describes the Vietnamese voltage stability issues. In order to deal with this problem it is proposed that a WAMS based application for voltage stability monitoring be developed.

In the literature on the subject there are many examples of Wide Area Measurement based voltage instability detection algorithms. PMU measurements have been used for voltage instability monitoring because of their greater precision rather than for their time-synchronization. Voltage stability, in fact is more a local than a network wide phenomenon, as it stems from the reactive power balance at the busbar where the voltage collapse occurs.

An effective voltage instability predictor is the S-Difference Index. This index is based on the variation of complex power) at the receiving end of a transmission line between two successive samples of the voltage stability algorithm. The complex power variation at receiving end of transmission line can be estimated as:

$$\Delta S_i \cong \Delta V_i^{k+1} I_{ij}^{k^*} + V_i^k \Delta I_{ij}^{k+1^*}$$

The variation can equal zero both when voltage and current variations are negligible, or when the two terms of the above sum have same absolute value and a phase difference of radians.

The first condition is the normal system operation behavior, when voltage and current phasors change at a very slow rate and as such may be regarded as negligible. The latter is the operating condition when a voltage collapse occurs. Every increase in the source of the transmission line is not reflected by any increase of the complex power at the receiving end, even though voltage and current phasors vary significantly over time.

The SDI algorithm is proposed as a voltage stability monitoring feature but it could trigger corrective actions, like under voltage shedding, once implemented as the trigger (or part of it) logic of an under voltage load shedding relay.

Although SDI is maybe the simplest implementation index, it is not the only voltage instability predictor based on phasor measurements. There are other algorithms and mathematical models developed for voltage stability monitoring, in most cases based on Thevenin equivalents (e.g. Voltage Instability Predictor – VIP, VIP++ [17], [18]). The precise methodology and the prediction algorithm to be implemented for voltage instability monitoring is a matter that should be investigated further taking account of the particular Vietnamese issues and the requirements for EMS.

F.5.4.2 Oscillation detection and monitoring

Another key application of the wide area synchronized system consists of a real time and off-line identification of oscillatory behaviors. As highlighted in the WAMS experience (see paragraph 'D.2.7.2'), the identification of unstable modes and the knowledge of their damping made it possible to determine the degree of stability of the operating condition. The subsequent analysis of the participation factors of such a condition can suggest the appropriate countermeasures that will need to be implemented [5].

There are lots of techniques that are available for stability monitoring and include nonparametric, parametric and subspace methods, maximum likelihood estimation, etc. All of them aim to identify weakly damped oscillatory behaviors, mainly inter-area, with a particular focus on the time at which these dynamics took place and their trend. All these techniques are usually fed by significant data from the power network such as active power flows or system frequency, where the power spectral density of the electromechanical modes is greatest.

These measures have merits and disadvantages that are often complementary and it is for this reason that the use of more than one method not only serves to validate the various improvements, but also helps to better validate the information obtained.

A proper implementation of these algorithms will facilitate full monitoring of electromechanical phenomena as well as benefitting the daily system operation activities by providing thorough and up-to-date measurements for evaluations and to improve the knowledge of the system dynamics.

Furthermore, post-event analysis of the results obtained by the application of these techniques, both of single events (contingencies, relevant oscillations, etc.) and of long sequences of events, could help to identify the characterization of the dynamic behavior of the Vietnamese transmission system and increase awareness of transient stability assessment. Towards this end it is worth highlighting the importance of statistical analysis of these results (see paragraph 'D.2.7.2'). The study of the distribution of frequency and damping has proven useful with the identification of typical oscillatory modes crossing the different parts of the electrical network and have aided in the investigation of the effects of possible different damping values.

Finally, this experience of monitoring oscillatory modes, especially inter-area, will be very useful for future interconnections with neighboring countries. In a large interconnected network, inter-area oscillations are frequent and it is important to be prepared to identify and adopt countermeasures against this type of system behavior.

F.5.5 NPT project evolution

In terms of the characteristics and capabilities of a WAMS project development as described above, it is useful to sum up some considerations and define possible implementation paths for a WAMS initiative in Vietnam.

The first step is a review of PMU positioning strategy, including the possibility of installing PMUs on the 220kV network, in order to improve the real-time system observability. As stated before, this phase will involve not only the operation and planning functions but also the asset management function whose contribution is crucial to achieve an effective PMU installation process.

PMU positioning strategy is significantly influenced by the type of applications to be developed for the WAMS system, so an identification of a list of desirable functions to be implemented is strongly recommended. The NASPI roadmap, described in D.4.1, is an excellent example of an appropriate approach with clear indications of priority, deployment challenges and time to complete for each application.

Moreover, the decision regarding the number of PMUs to install as well as their location in the network and other related factors will determine the overall impact on the telecommunication system. This must be carefully considered to understand the required improvements to support the WAMS implementation.

The NPT's pilot project is a good starting point, especially for applications and functional testing, but in order to develop the WAMS project on a larger scale over the mid-term time scale the most crucial step is an accurate analysis phase focusing on all the issues described above and involving all the TSO functions impacted by this kind of initiative.

F.6 Lightning Location Systems

As stated in 'Annex 2b.v', NPT considers the weak performance of exposed 220 kV lines during lightning storms as one of their most serious problems as this has been responsible for several supply disruptions in the Vietnamese transmission network. Installing surge arresters on transmission lines in areas with a high incidence of thunderstorms is one possible remedy to minimize the impact of lightning on grid resilience and reliability.

F.6.1 Transmission Lines Surge Arresters

NPT is currently considering the installation of these devices and the first transmission line involved in the project is the 220kV Tuyen Quang–Bac Kan–Thai Nguyen.

There are different options to equip lines with these components, amongst which is either the installation of surge arresters on the entire route or only on those towers known to have already been struck by lightning or on towers located in high mountains. The costs for implementing these various solutions are obviously very different.

This current project cannot be considered a Smart Grid project, given that the arresters are conventional components and their installation is a traditional, well understood and mature remedy.

On the contrary, given that storms often create significant problems for the transmission network, especially in specific regions, the adoption of a Lightning Location System (LLS) able to collect real-time data and precise statistics about frequency and the hazardous nature of lightning strikes should be considered as one of the key applications in the Smart Grid roadmap.

Such an initiative has not been considered by NPT in its roadmap, but the development of LLS is an opportunity for achieving significant benefits for the transmission system in Vietnam. This system improves overhead-line engineering and design from the outset and streamlines network operations and the activities of field crews.

With the help of an effective LLS application the installation of surge arresters can be achieved on the basis of smart design management, engineering, operation and maintenance processes.

The following section describes the guidelines for developing a LLS and highlights the benefits of the data acquired by such systems.

F.6.2 Lightning Location using simulation algorithm

Firstly, it is worth noting that it is possible to use simulation algorithms to emulate the location of LLS devices however this technique has quite limited abilities.

There are complex tools that support detailed simulations of electrical line behavior in the vicinity of a lightning strike. The overvoltage propagating along the line and the effect of surge arresters positioned at different points can be studied, to analyze the effects of the entire lightning spectrum and, thus provide evidence of the best choices for surge arrester positioning.

However, in order to quantify the amount of potential damage, it is necessary to know the mean lightning density at ground per year over the region traversed by the electricity line being considered. To get the best out of simulation algorithms lightning trend information needs to be very precise but as the Vietnamese system has not had the facility to capture such information about past lightning events available simulation tools for lightning location cannot be considered a viable strategy.

Whilst the installation of LLS requires a significant investment, it will provide maximum precision and accuracy in collecting data regarding lightning events, as detailed in paragraph 'D.2.8'.

F.6.3 Guidelines for Lightning Location System development in Vietnam

To implement a LLS, a dedicated planning phase is needed, but such an activity is outside the scope of this document. However it is useful to provide a short list of the basic actions required to deploy a LLS across the entire country.

The basic phases are:

a. The evaluation of all the available technologies with respect to the specific needs of all the transmission utility functions that could benefit from such a system.

b. The evaluation of the number of sensors needed to cover the country with homogeneous and high detection performance, event discrimination, location accuracy and 24/7 availability.

c. The evaluation of the orography and consequently the identification of the possible ideal locations for the sensors (electromagnetic noise, structural shields, physical security, terrain, telecommunication, etc.).

d. Appropriate contractual agreements with local site owners wherever necessary.

e. The execution of all civil and electrical works at the identified sites, including power and telecommunication cabling if needed.

f. The implementation of an Operational Center provided with specific power and telecommunication schematics and containing the main server for data analysis where all sensor data will be received, processed and stored.

g. The fine tuning of LLS (using the most immediately available data), implementing site corrections of detection parameters and thresholds where needed.

h. The assignment of dedicated and properly trained staff.

F.6.4 Benefits of Lightning Location System data

Earlier sections have highlighted how the development of LLS can drive the planning phase for installing surge arresters. Here, it is worth underlining that not only Grid Planning and Asset Management, but also System Operation (all of which functions are the responsibility of NLDC in Vietnam) would benefit considerably from LLS technology.

The data acquired by LLS provides estimations for each lightning strike, in terms of both the location and return-strike current amplitude. This information can be very useful for System Operation to understand whether lightning is the real cause of relay operation during thunderstorms or not. Therefore, the data coming from LLS is usually integrated with data obtained from monitoring systems that record protection actions.

In particular, the studies presented in the literature ([19], [20]) aim to understand the correlation between a lightning event and relay operation by means of establishing a time window and spatial distance criteria. Lightning is assumed to be the cause of a line fault if the two events (lightning and relay operation) are recorded within a time window of a few seconds and the distance between the estimated strike location and the line is lower than a chosen spatial threshold. In this way for each fault it can be determined if it is due to lightning or not, showing eventual critical behavior for specific areas or line branches.

Moreover, LLS is also extremely useful in fast tracking thunderstorms, thus providing a forecast of where a thunderstorm will strike and providing a means of anticipating it by choosing alternative dispatching routes or by alerting relevant field teams. This will certainly help in reducing the time to repair and generally bringing about power quality improvement.

Further, it is worth underlining that, thanks to the storage of historical data on lightning events (with the availability of an adequate time window), it is also possible to calculate the mean flash density at ground level for each area of a country. Recently a specific IEC Standard has ratified the LLS as a suitable and reliable application to calculate this value.

This parameter could cover every square kilometer of Vietnam and, consequently, the most lightning prone areas could be avoided when installing a new line.

Using this parameter for each kilometer of a power line the number of lightning events per year can be defined and expressed as a mean, thus giving an indicator for lines or branches that are more or less exposed. This information, together with the characterization of the lightning-fault behavior of each branch described previously can be a clear indicator of the best location to install lines or to tune specific protections.

F.7 Static Var Compensators

A SVC is a power quality device, belonging to the family of FACTS systems, which employs power electronics to improve the voltage profile by continuously regulating the injected or absorbed reactive power.

FACTS devices, thanks to their speed and flexibility, are able to provide the transmission system with several advantages such as:

a. Transmission capacity enhancement;

b. Power flow control;

c. Transient stability improvement;

d. Power oscillation damping; and

e. Voltage stability and control.

Some technical details about the FACTS technology are shown in 'Annex 3'.

The table shown in Figure 49 displays the issues and network problems that can be efficiently resolved by the installation of the most common FACTS devices within the network grid and summarizes the main characteristics of each type of application.

Looking at the problems and challenges of the Vietnamese transmission network, the main concerns are related to both power transmission capacity/controllability and voltage profile control and stability. In principle, FACTS

FIGURE 49: FACTS MAIN DATA AND CAPABILITIES

Device description	SVC	STATCOM	TCSC
Device ratings (in MVA)	100-850	100-400	25-600
Future trend of device ratings	Towards higher values	Towards further deployment	Towards further deployment
Operational experience	>30 years	>20 years	>15 years
Lifetime	40 years	30 years	30 years
Converter losses (at full load, per converter)	1-1.5%	1-2.5%	0.5-1%
Availability	> 98%	> 98%	> 98%
Device capabilities			
Transmission capacity	■	■	■■■
Power flow control	■	■	■■
Transient stability	■	■■	■■■
Voltage stability	■■■	■■■	■
Power oscillation damping	■■	■■	■■
Control of wind farms reactive power output	yes	yes	no
Investment costs	■	■■	■

■ — Small; ■■ — Medium; ■■■ — Strong

Source: Technical University Dortmund, 2010, (19) devices in either series or shunt configurations can be used successfully to address both problems.

In practice however, it is necessary to note that in the 500 kV systems, which are the backbone of the Vietnamese network, the 500 kV lines are already equipped with fixed compensation (SC).

Furthermore the line sections are relatively short with distances in the central area ranging between 259 to 327 km, as there are many intermediate 500/220 kV substations. So, based on an initial assessment, the application of FACTS series compensation systems does not seem very attractive. In any case, only a detailed network system study can confirm this initial indication.

On the other hand, the application of shunt type devices can be considered appropriate for addressing the problems with control of reactive power and in turn ensure control of the voltage profiles.

As described in 'Annex 3', the role of an SVC system is to adjust the amount of reactive power compensation to the actual system needs and then to control voltage which also has a very positive impact on dampening power oscillations, thus also increasing the transmission capacity. In fact, the very first examples of the installations described in Annex 3, such as the first application in USA for the EPRI-Minnesota Power & Light project commissioned in 1978, have already achieved significant and clearly identified benefits with SVCs enabling a 25% power increase on lines where they were installed.

Therefore, in the following sections the features and possible applications of SVC systems are analyzed in more detail and with reference to specific characteristics of the Vietnamese network.

SVC systems are already in use on the Vietnamese grid in order to counteract the problems related to the voltage profile fluctuation.

Two SVCs have already been installed, the first one on the 110 kV bus bar of the 220 kV Viet Tri S/S (+-50 MVAr) and the second one on the 22 kV side of the 220kV-250 MVA transformer of the 220 kV Thai Nguyen S/S (+/-50MVAr).

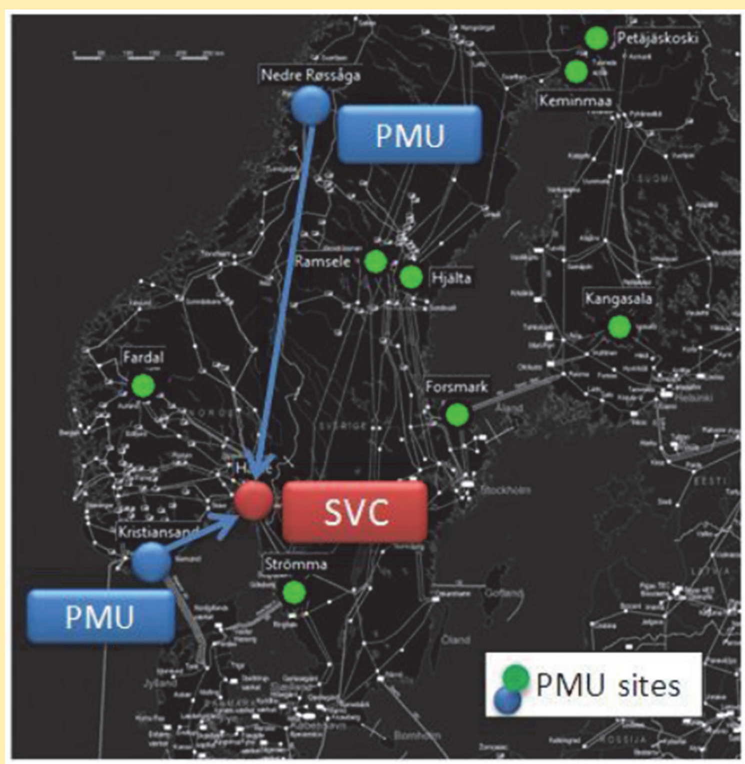
Two other SVCs with a regulation range of +/- 130 Mvar have been approved and will be installed on the tertiary winding of the 500/220 kV step down transformers in two stations of the 500 kV North-South transmission system, located in the central and southern area, namely DaNang and O'Mon.

They are intended to provide dynamic support of the voltage, optimizing the exchange of reactive power along the backbone link.

The proper setting and control of SVCs, including specific stabilizing loops, could prove effective in stabilizing the network, increasing the transmission capacity, optimizing the voltage profile and consequently also reducing the losses along the lines without changing the topology of the electrical system. For that reason they are definitely considered part of a Smart Grid.

In this regard, a very interesting example of the use of a SVC system within a typical smart application is shown in Figure 50, where a specific installation of an SVC system is shown within the Nordic European grid system.

FIGURE 50: EXAMPLE OF WIDE-AREA POWER OSCILLATION DAMPER IMPLEMENTED WITH A SVC



Source: IEA, 2013, (20)

In this case, A Wide-Area Power Oscillation Damper was implemented controlling a 180 Mvar TCR Static Var Compensator (SVC) installed in the Hasle substation of the Norwegian 420 kV transmission grid.

The SVC uses voltage phase angle signals from two distant locations in the Norwegian grid as inputs to the damping controller. The damping controller modulates the voltage reference set point used by the SVCs voltage controller, thereby creating a damping effect.

The Wide-Area Power Oscillation Damper is an extension to the existing Power Oscillation Damping (POD) controller that uses local measurements and suitable switchover logic to allow for the choice of no damping control, local damping control or wide-area damping control.

In this way, the issue of low frequency inter-area power oscillations is resolved very effectively through the use of special controls on the FACTS device and works as a suitable control strategy on the power system stabilizers loop.

However, like other FACTS devices, the SVC is an expensive system. Therefore it is important to define the implementation strategy correctly and to integrate it with the operation of the traditional system components and the normal practices for voltage regulation.

In particular, it is very important to find the optimal location and the correct capacity of the SVC in a power system so that voltage profiles may be effectively improved thus optimizing the investment.

The proper location and sizing of SVC systems must be based on a detailed system study and design analysis of the network.

In particular the assessment of the benefits that can be achieved thanks to the installation of the SVC systems requires the execution of appropriate system studies. In principle, the fast system response of the regulation provided by the SVC can reduce the risk of outages that could affect large areas of the network, with a significant impact on the levels of reliability achieved, which leads consequently to a substantial reduction in the System Average Interruption Duration and System Average Interruption Frequency Indices.

Re-locatable systems may be considered for this issue, given the rapid development and possible reconfiguration of the Vietnamese grid, which will immediately change the requirements and shift the location of critical nodes of the system.

In comparison with conventional large SVCs, a re-locatable SVC provides additional performance benefits:

a. Easy and quick relocation in response to network design changes.

b. By making a SVC re-locatable, dynamic voltage support can be delivered where it is most needed in the power grid to address current demands for network stability. Then, when the system configuration changes in response to the demands of a changing power market, the SVC can be relocated to enable the system to adapt to the new situation.

c. Moreover, considering that a re-locatable SVC allows for the unit to be moved from one place in the grid to another on an ad hoc basis, SVCs can be considered as a temporary solution to improve network performance until other long-term reinforcement measures can be implemented.

d. In this way, a re-locatable SVC can be considered as an element which could both facilitate and make less critical the definition of the required phases for the development and implementation of the new substations and new lines which necessarily involves much longer time scales to accommodate the design, location selection, installation and commissioning phases.

The unbundling practices applied to the electricity market that produce a transition from a centralized system to a more deregulated environment, tend to increase the difficulties for the system operator and planners to forecast future development and expansion of the transmission network by more than a few years ahead.

The installation of a new generating plant or new high voltage connections may greatly strengthen weak points and render an SVC installed in a specific area practically redundant after only a few years of service, whereas other developments may result in the closure of some generating plants or in an unexpected change in load profiles, with consequent weakening of the network in that specific area.

The result is that a SVC installed as fixed substation plant, to meet a medium- to long-term need with a typical anticipated lifetime of 25-30 years or more may then not be connected to the right node at the right time to provide the required voltage support for the network. This is the more obvious disadvantage of a fixed SVC system in the transmission grid, especially in cases where the network is in a state of flux, as in Vietnam.

This is the reason why various TSO have specified re-locatable SVCs as the preferred solution.

In order to get a re-locatable configuration, the SVC installations need to be compact and avoid any permanent fixed structures.

Outdoor equipment (reactors, capacitors, etc.) are normally arranged in-groups of components, mounted on skids or special frameworks, which can be easily carried, by road or rail, with just the minimum site activity for mounting or dismantling.

Other more sensitive components of the SVC, such as the thyristor valves, Protection & Control modules, auxiliaries, etc. are installed within transportable cabins to provide weatherproof housing.

Whenever possible, the most convenient solution is to connect the SVC system to the tertiary winding of the substation transformers. In this way it is not necessary to provide for the installation of a dedicated SVC transformer.

On the other hand this solution implies a limitation on the size of the SVC system according to the standardized rating of the transformer and can lead to the need to provide a larger number of SVCs, with reduced ratings, distributed across multiple transformers.

The major effort required for the definition of the characteristics of a re-locatable SVC system, however, is related to the electric design of the system, which must be aligned with the requirements to allow the installation of the system in different areas of the network as well as factoring in different operating conditions and a wide range of system parameters.

The technical solution normally includes the use of sections of compensation (typically TSC) with binary multiple power steps (see example of Figure 51: 102040 Mvar steps, with corresponding operating points). In this way the rating, tuning and implementation of the system can be easily modulated to meet the needs of the new installation site.

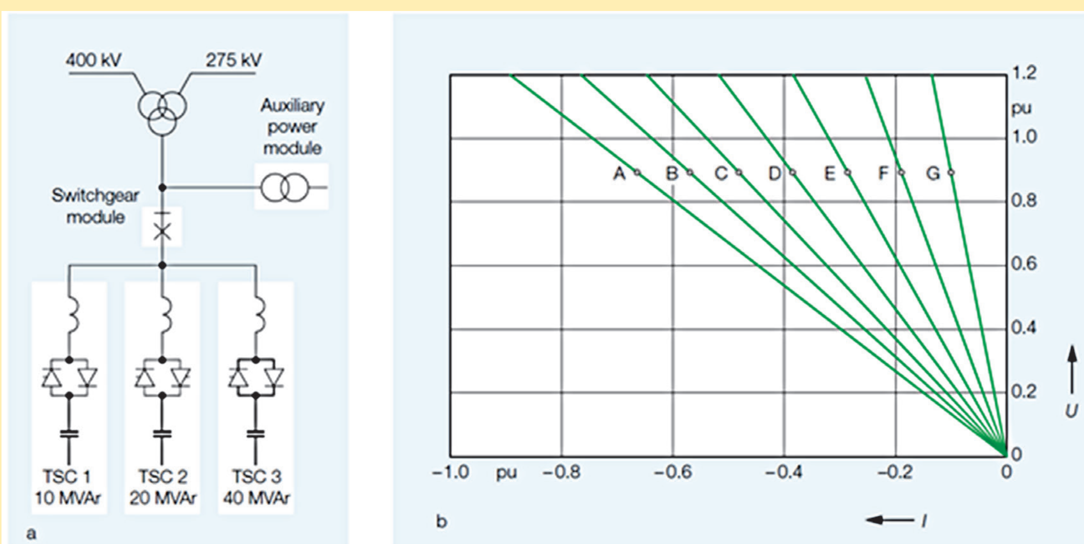
It is worth noting that the development of the STATCOM system lends itself to this level and type of modularity and is easily relocatable.

In this case the compensation modules are not only TSC systems but also STATCOM voltage source converters, which can continuously modulate the exchange of reactive power with the network. This solution is simpler but inevitably more expensive.

The previous section 'D.3.2' provided a detailed analysis relevant to the application of SVC systems in the UK and includes an extensive description of the use of re-locatable systems.

The concept of re-locatable SVCs has either been implemented or merely studied in other countries, where the need to provide voltage support must be accommodated

FIGURE 51: SYSTEM CONFIGURATION AND OPERATING POINTS FOR A RE-LOCATABLE SVC



Source: SIEMENS, 2013, (17)

in the context of a fast growing, dynamic and rapid development of the transmission system, such as in South Africa and Algeria [21].

F.8 High Voltage Direct Current technology

High Voltage Direct Current (HVDC) technology has proven its reliability and is an effective option for specific applications such as long distance bulk power transmission, long submarine cable links and interconnection of asynchronous systems.

Countries like Brazil use this technology to carry the large generation from Itaipú (one of the largest hydro power plants in the world) and also for interconnecting their north and northeast areas with the south-southeast areas.

Two different technologies are available today, viz. thyristor converters, also called Line Commutated Converter (LCC), see Figure 52, which shows examples of systems that have been in service since the 50s, and transistor converters, also called self-commutated Voltage Source Converter (VSC), see Figure 53, developed in the late 90s [22]. The peculiarities of each HVDC technology are summarized in Figure 54.

The key benefits of HVDC are in terms of both **increased transmission capacity**, compared with conventional HVAC and **power flow controllability**, which can enhance the stability of the link and of the surrounding electrical system and thus increase the transmission capacity of conventional AC systems interconnected by the HVDC link.

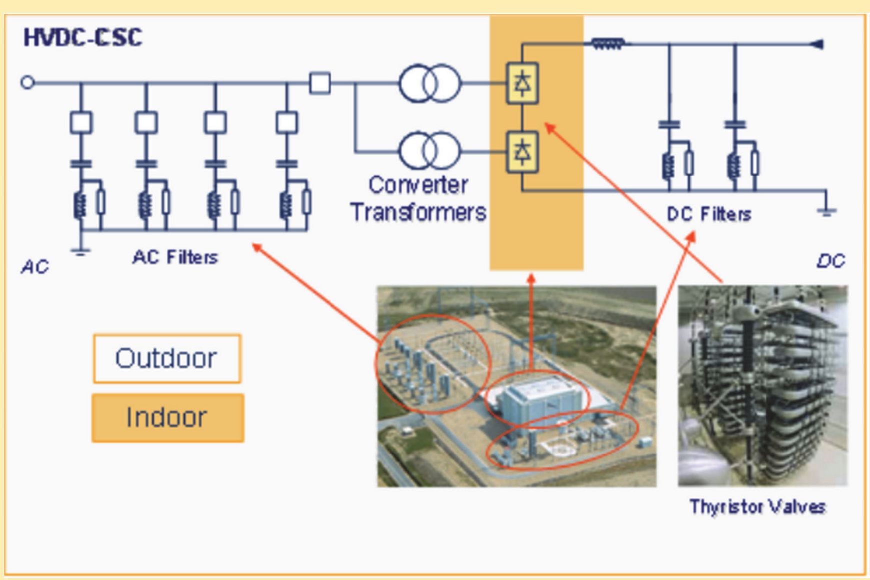
The accurate control of the active power in the HVDC link can ensure significant stability improvements for the link itself and for the surrounding AC system. In fact, unlike conventional HVAC transmission, the active power flowing through an HVDC link is not determined by the link impedance in relation to the impedances of the neighboring transmission lines, but only by the settings of the HVDC converter control.

The HVDC transmission link can operate at a fixed working point, which can be maintained or rapidly regulated during disturbances on neighboring transmission lines and AC grid sections.

This characteristic prevents the HVDC link from overloading when a neighboring transmission line is lost and assures a consistent transmission capacity in terms of the line rating.

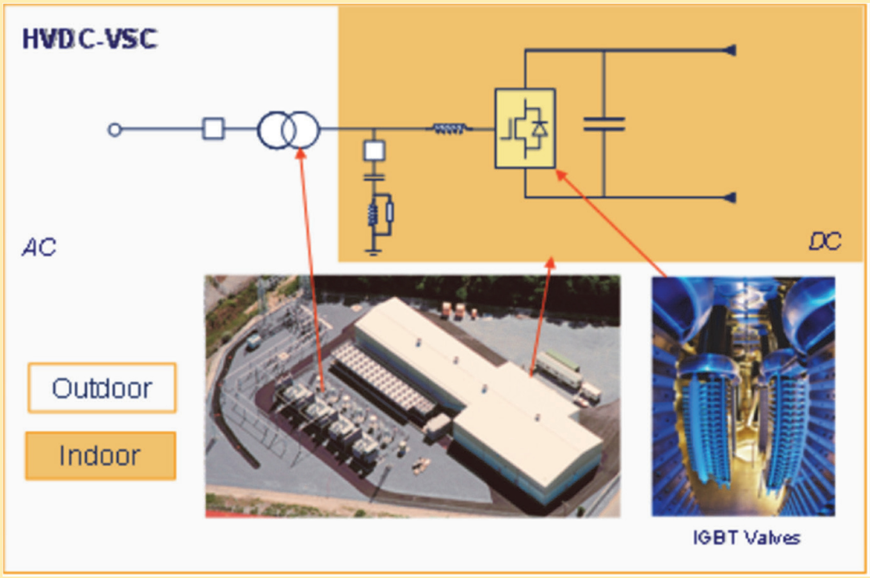
The consistent transmission capacity of the HVDC link is assured without any limitation caused by network congestion or loop flows on parallel paths as well. Link capacity with HVDC is generally higher than that of extra high voltage AC transmission and also lowers the transmission cost per MWh.

FIGURE 52: LCC HVDC CONVERTER CONFIGURATION



Source: ABB, 2013, (8)

FIGURE 53: VSC HVDC CONVERTER CONFIGURATION



Source: ABB, 2013, (8)

FIGURE 54: HVDC MAIN DATA AND CAPABILITIES

System description	CSC-HVDC	VSC-HVDC
System ratings in operation	±800 kV, 3000 MW	±150 kV, 350 MW
System ratings available	±800 kV, 6400 MW	±300 kV, 1100 MW
Future trend of system ratings	towards higher ratings	
Operational experience	> 50 years	~ 10 years
Lifetime	30-40 years	30-40 years(1)
Converter losses (at full load, per converter)	0.5-1%	1-2%
Availability (per system)	> 98%	> 98%
System capabilities		
Transmission capacity	■■■	■■
Power flow control	■■■	■■■
Transient stability	■■	■■■
Voltage stability	■	■■
Power oscillation damping	■■	■■■
Reactive power demand	■■■	■
System perturbation	■■■	■
Reactive power injection possible	no	yes
Easy meshing	no	yes
Limitation in cable line length	no	no
Ability to connect offshore wind farms	no	yes
Investment costs per MW	■■	■■■

Legenda: ■ — Small; ■■ — Medium; ■■■ — Strong;

Source: Technical University Dortmund, 2010, (19) Moreover the HVDC power flow controllability is also very beneficial for the parallel AC transmission as it frees up transmission capacity on neighboring AC lines.

This positive effect on neighboring AC network paths has to be taken into account during power flow analyses in order to perform a complete cost benefit assessment of the HVDC system impact on the transmission system.

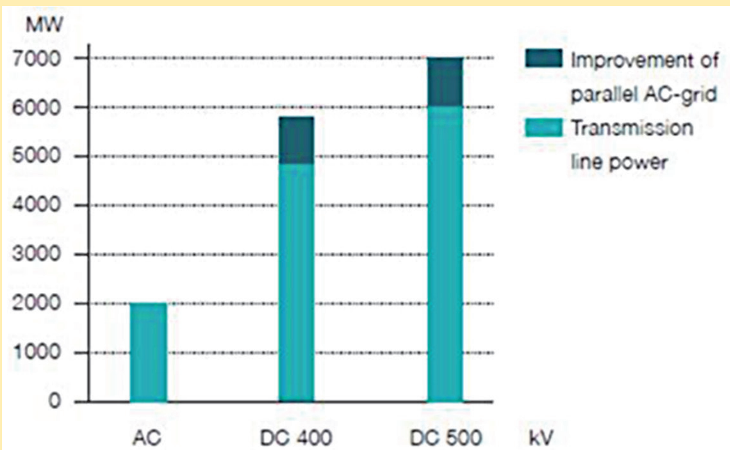
Studies performed on typical configurations, with AC and DC parallel corridors, shows significant increase in the transmission along the AC lines, with final utilization close to the thermal limits of the system, see example shown in Figure 55.

The most recent technology, the VSC converter, is even more flexible than the conventional line-commutated converter, since it allows a faster and more independent control of both active and reactive power, as shown in Figure 56.

In this way, the converter can contribute to the regulation of the AC system voltage like a generator during emergency situations and can operate at a fixed value of transmitted power even in the presence of fault conditions in neighboring lines. These specific features help to improve the overall stability of the surrounding AC power systems. Furthermore, since HVDC VSC can contribute to power oscillations damping, it also enhances network stability during emergency situations.

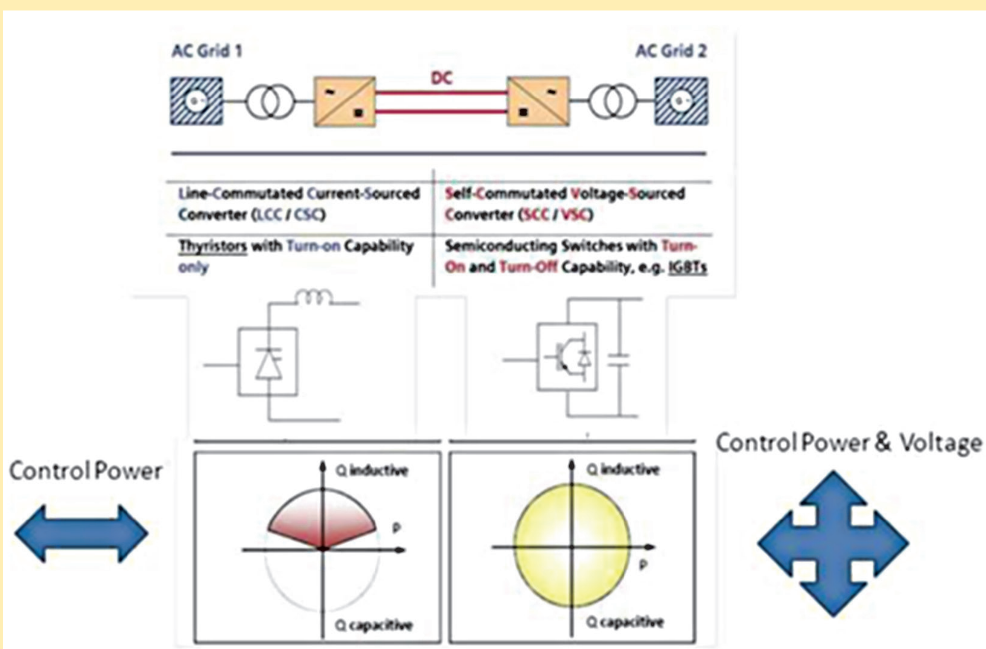
Since the VSC converter does not require the presence of an active AC supply (as opposed to the LCC converter, where the

FIGURE 55: TRANSMISSION CAPACITY IMPROVEMENT



Source: IEA, 2013, (20)

FIGURE 56: LCC AND VSC REACTIVE POWER CAPABILITY



Source: IEA, 2013, (20)

availability of a sufficient level of short-circuit power compared to the rated power of the converter is required), black start capabilities can also be ensured by VSC-HVDC, to allow the fast re-energizing of an AC network following a system blackout.

A broad range of application control functions can be implemented in a VSC-HVDC system for enhancement of the steady-state and dynamic performance of an AC network. These control functions are shown in Figure 57 split into three categories along the time line for a disturbance:

a. Pre-disturbance phase;

b. Transient phase; and

c. Post-disturbance phase.

Other positive aspects that can be associated with the use of a HVDC system are in general:

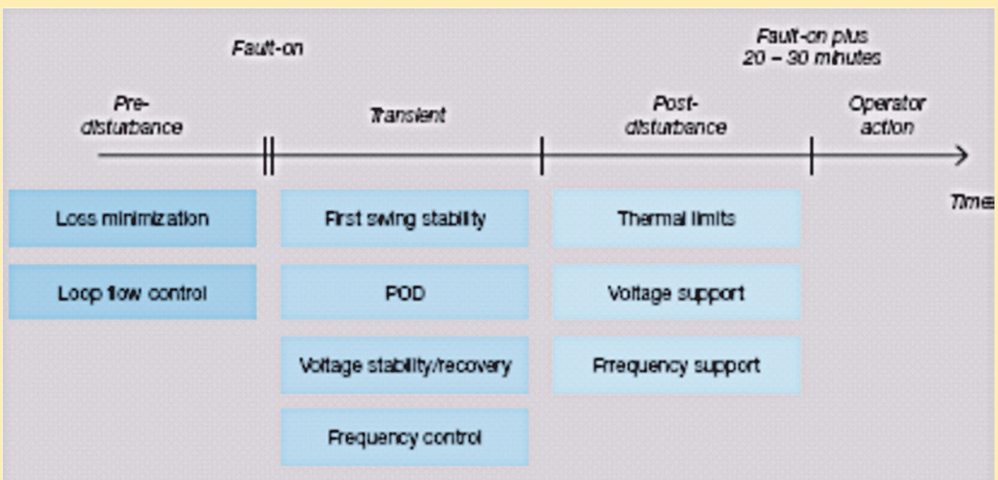
a. A very high level of reliability and availability. This is not because of highly stringent component requirements in VSC systems but is rather a function of the modular design of the converter bridge, which is inherently fault tolerant.

b. A level of resulting transmission losses (converters + OHTL or cables) over significant distances is lower than those present in an equivalent AC system.

c. In particular, the development of multilevel VSC converters has also reduced the losses for the VSC converter to levels that are comparable with the LCC, see Figure 58, showing the reduction trend in VSC converter losses [23].

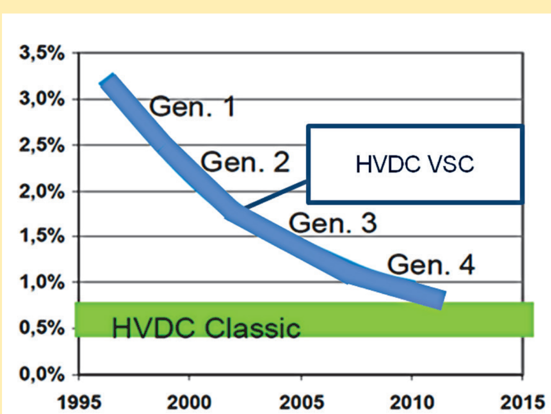
d. The choice of HVDC instead of HVAC transmission has a reduced environmental impact as, for the OHTL, the right-of-way can be reduced by approximately 30-50%. The electromagnetic emission of HVDC lines does not pulsate and can be forced to minimum values to ensure significantly lower electromagnetic pollution compared to the emissions of conventional HVAC transmission and this includes the related effects in term of audible noise and possible radio frequency interference with other systems.

FIGURE 57: VSC CONTROL FUNCTIONS VS. DISTURBANCE TIME LINE



Source: ABB, 2013, (8)

FIGURE 58: VSC LOSSES OPTIMIZATION TREND



Source: ABB, 2013, (8)

Although the investment costs of a LCC or VSC HVDC converter station are higher than for a conventional AC substation, the overall investment costs of a DC transmission link can be lower than for a corresponding AC interconnection given a minimum transmission distance (i.e. "break-even" distance).

This break-even distance is highly contingent upon the specific project parameters and can be affected by various constraints and specific needs of the network under consideration.

In addition to the classic HVDC applications described above which take advantage of their specific characteristics and in particular of their inherent controllability several TSOs and manufacturers are considering their future use on production networks. There are already several examples of real world applications already implemented or in an advanced stage of installation and that may establish a new paradigm for emerging grid architectures based on a combination of HVDC and conventional HVAC solutions in conjunction with the use other active control equipment to deliver a more efficient and reliable grid system [24].

An AC and HVDC combined grid will be better able to accommodate and respond to new requirements resulting from a rapid evolution of the electricity markets such as the need to:

a. Actively integrate new types of power generation and consumption models;

b. Enable new business opportunities and market models;

c. Allow more coordinated planning and integrated operation of the grid given the expansion of most networks caused by a growing number of international connections; and

d. Support and facilitate the introduction of new market rules at both national and international level.

Given the capabilities assured by the HVDC systems and their impact on the operation of the AC transmission grid this technology could be also be considered as part of a Smart Grid initiative. See the example of increased stability of combined AC and DC system shown in Figure 59.

The analysis of solutions that could integrate one or more HVDC links in the AC grid implies the verification of all key parameters that optimize the operation of the network, as already pointed out, in terms of the expected impact on:

a. The reliability of the transmission system;

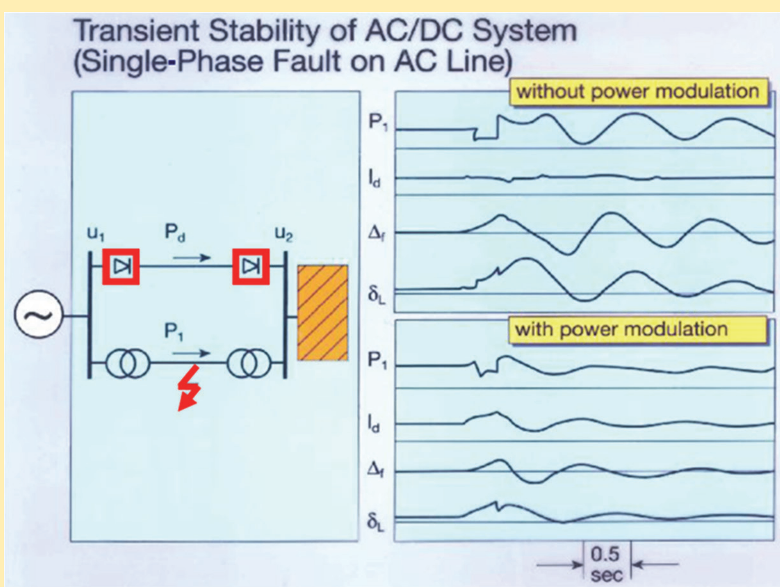
b. Power system controllability;

c. Increased transmission capacity;

d. Minimizing transmission losses; and

e. The definition of integrated solutions with reduced environmental impact.

FIGURE 59: TRANSIENT STABILITY ENHANCEMENT WITH HVDC PARALLEL LINK



Source: Friends Of the SuperGrid, 2012, (21) Based on the above comments, the possible integration of HVDC interconnections within the AC network can also be considered for the Vietnamese network over a **long-term time scale** given:

a. The high rate of growth of the grid expected for the near future, which may lead to congestion problems and bottlenecks in the main load area of the grid with the need to control the levels of short circuit current and avoid loop-flows; these issues are discussed in more detail in the following section. Considering, however, the rate of development of the network and new installations planned in terms of 500 and 220 kV lines and new substations, as per the following table of Figure 60 derived from master plan VII, this type of problem could actually arise in various areas of the country, as evidenced by international experiences in other countries.

b. The possible development of generation from renewable sources that could be located at some distance from load centers. In fact master plan VII, prioritizes the development of renewable energy sources for electricity production, increasing the percentage of electricity produced from these energy sources from 3.5% of total electricity production in 2010 up to 4.5% in 2020 with a target of 6.0% for 2030. Also in this case, international experiences concerning the presence of a strong component of RES generation, in particular if located in peripheral areas of the country, has shown the tendency of dedicated HVDC links to achieve better management of these sources. HVDC technology allows for easier interconnection of RES generation with a substantial decoupling with respect to all those disturbances that are associated with this intermittent type of generation. Again, these issues are discussed in detail later on.

c. Vietnam's policy regarding international interconnections to power grids of other countries in the region has a target in terms of total import capacity of about 2,000–3,000 MW for 2030. Some of these connections in terms of power levels and length of the line, fall within the range of applications that could benefit from HVDC technology.

With regard to the development of interconnections with other TSOs, the option of using a HVDC system allows the definition of a solution in which the operation of the interconnected AC systems is substantially decoupled.

In this case the technical standards applied by each TSO do not need to be altered which is helpful as they can vary significantly between countries.

This applies for example to:

a. Characteristic types and ratings of network components;

b. Operating modalities;

c. Fault responses;

d. Setting and calibration of the control systems; and

e. Specification of protection and control apparatus.

A solution based on a HVDC link would allow for easier negotiation of potential operating conditions and exploitation of future interconnection between the TSOs involved.

This favorable situation is achieved by eliminating all the potential technical limitations and constraints that could make the project less attractive or even inconvenient or impractical for the participating agencies thus allowing them to focus exclusively on the definition of the most favorable economic conditions for the exploitation and utilization of the proposed new infrastructure.

Considering the potential long-term prospects for the use of HVDC systems in the Vietnamese network, it is appropriate to define and identify some key elements

FIGURE 60: PLANNED DEVELOPMENT OF 500/220 KV EVN/NPT GRID

Item	Unit	2011 - 2015	2016 - 2020	2021 - 2025	2026 - 2030
500 kV substation	MVA	17,100	26,750	24,400	20,400
220 kV substation	MVA	35,863	39,063	42,775	53,250
500 kV line	km	3,833	4,539	2,234	2,724
220 kV line	km	10,637	5,305	5,552	5,020

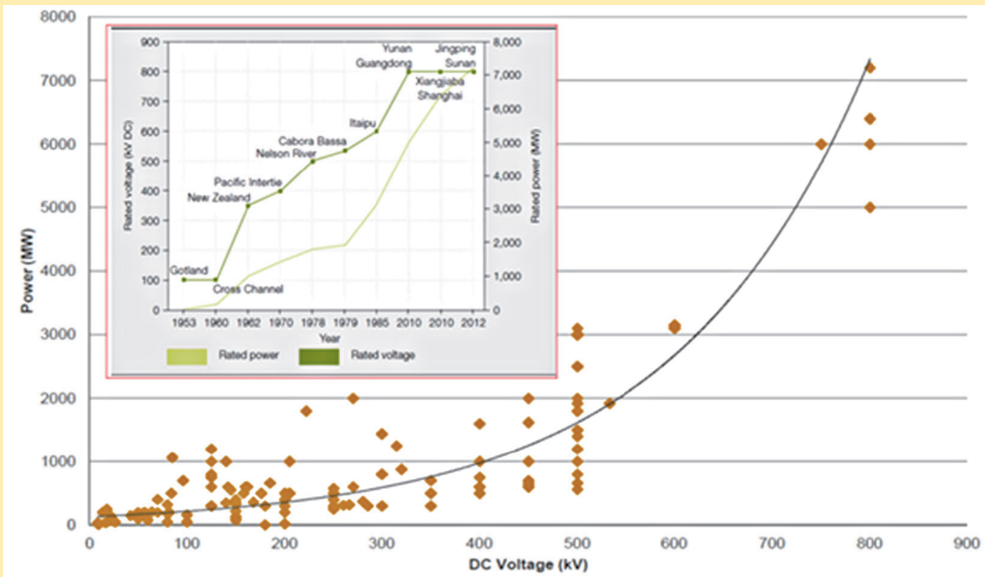
Source: NPT-World Bank, 2013, (18)

concerning the development of the related technology in an attempt to identify possible development trends and implications of specific applications in the future.

The following Figure 61 shows the growth trend for the transmitted power and the voltage level applied for HVDC systems of the LCC type. The trend for VSC converter systems instead is shown in Figure 62.

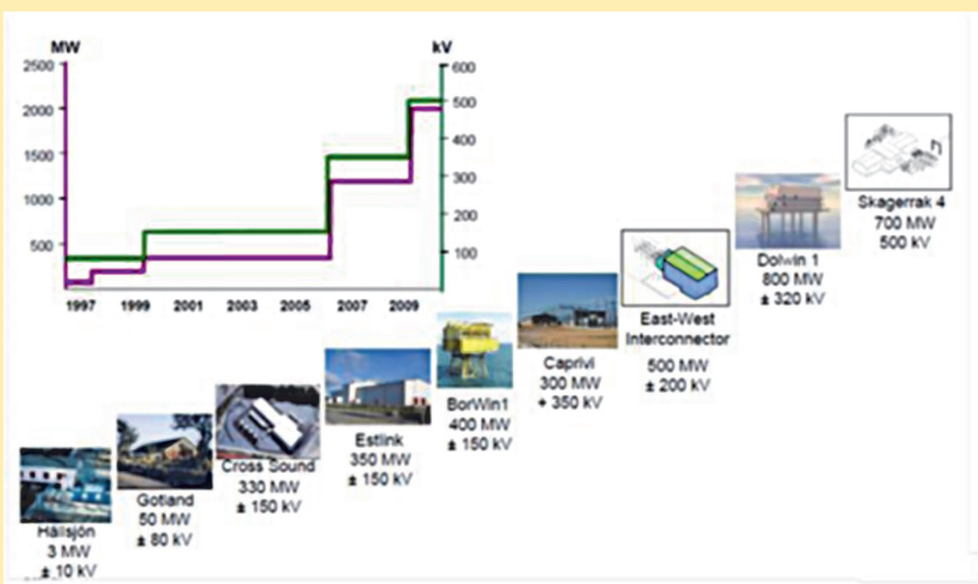
The comparison between the two figures shows that the LCC systems are increasingly used for bulk power transmission over very long distances, whereas VSC systems

FIGURE 61: DEVELOPMENT TREND OF LCC CONVERTER TECHNOLOGY



Source: ABB, 2013, (8)

FIGURE 62: DEVELOPMENT TREND OF VSC CONVERTER TECHNOLOGY



Source: IEA, 2013, (20)

are being used in an expanding range of applications for transmission over medium distances with increasingly higher power levels in particular within AC integrated systems, as clearly shown in Figure 63.

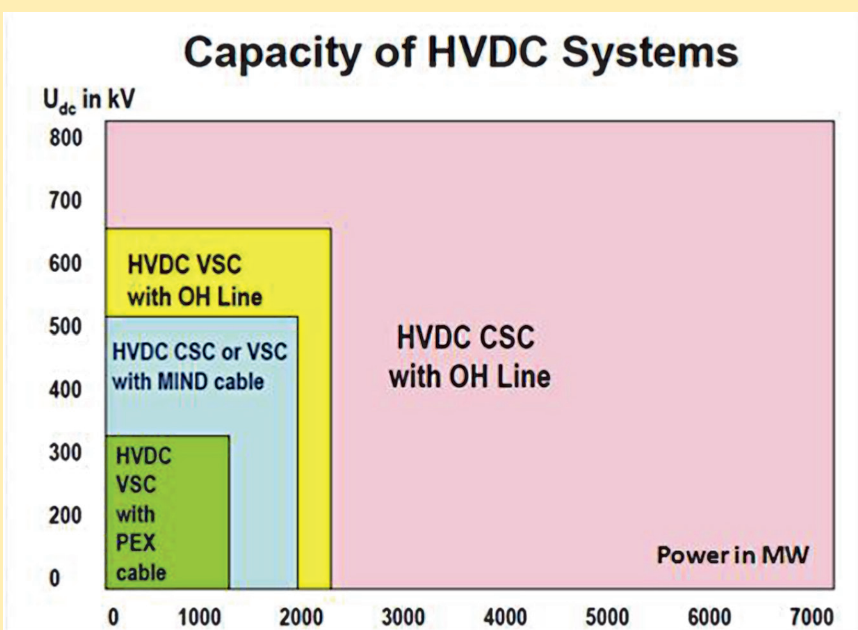
Based on the actual trends and development scenarios predicted for the electrical system in Vietnam and in particular the potential development of new interconnections with neighboring countries (Laos, Cambodia), it is likely that the most appropriate option to integrate a HVDC system within the current or future AC network, would be based on VSC technology. The gradual adoption of this technology particularly across the EU and the USA will deliver improvements, enhancements and international standards as well as decreasing costs making it ever more attractive and affordable for the Vietnamese to consider as a future enhancement, since the application of the traditional LCC technology seems increasingly intended for applications with power, voltage levels and distances above the levels of interconnectedness expected for Laos and Cambodia. However, in the case of development of bulk import from China this type of more traditional technology may still be considered.

The application of HVDC technology for the Vietnamese network can be seen as a possible solution for dedicated interconnections to the networks of neighboring countries based on the experiences of international projects such as Caprivi, in Africa (350 kV/950 km, 300 MW monopole) but with additional future proofing by including additional converter and bipolar operation/expansion to 600 MW.

However, considering the technology available today, a DC 500 kV link circuit could provide a transmission capacity similar to that of a dual circuit 500 kV AC line at about half the cost [25], see Figure 64, making the HVDC solution economically viable for distances less than 600 km (but the break-even distance is heavily dependent on the costs for line construction civil works) with power delivery capability of up to 2,000 MW [26].

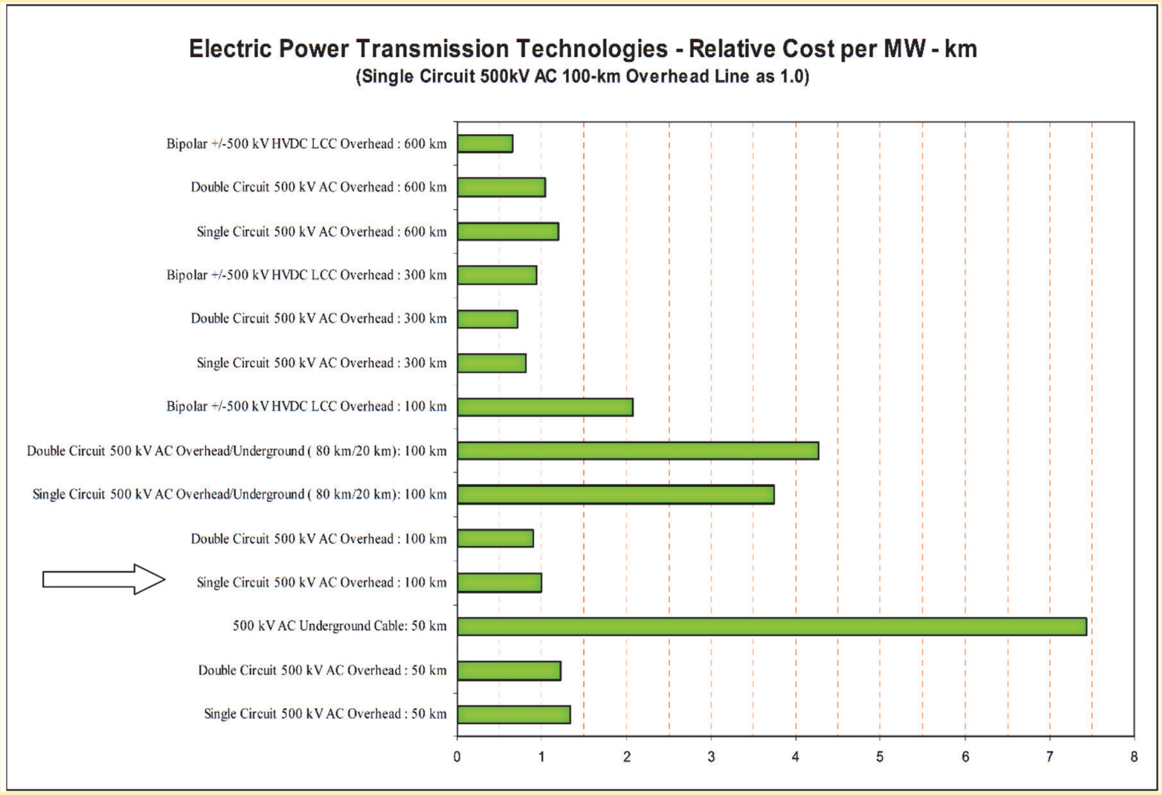
HVDC technology will serve the needs of the Vietnamese electrical network very well in the light of the targets defined in the national master plan for power development over the 2011–2020 period, such as developing a balanced capacity of power sources in the Northern, Central and Southern regions, ensuring the reliability of power supply systems in each region in order to reduce transmission losses, sharing capacity reserves and efficiently exploiting hydro power plants in all seasons. The implementation of a HVDC system could deliver significant benefits to the Vietnamese transmission grid given the predominant north-south alignment of its topology particularly in terms of the 500 kV backbone configuration but primarily for the significant polarization of load

FIGURE 63: APPLICATION AREAS FOR LVV AND VSC CONVERTERS



Source: IEA, 2013, (20)

FIGURE 64: TYPICAL RELATIVE COSTS FOR DC AND AC OHTL'S



Source: Alberta Energy, 2009, (22)

and generation in the two extremities since SPC and NPC are not only the regions with the highest share in power consumption but also the ones with the highest growth rate.

A HVDC system would deliver a substantial reinforcement of the global conditions of north-south load flow for a relatively limited investment.

This option could be technically and economically beneficial. In fact, a north-south point-to-point DC transmission link could provide:

a. A cost-efficient configuration where the overall cost of the DC system would be less than the global investment need for the reinforcement of the AC system such as additional lines or modifications of the existing stations/new substations;

b. A transmission of bulk power between the two main areas achieved with a substantial reduction of transmission losses;

c. A significant increase in the reliability of the system thanks to the lower levels of the RAM associated with a HVDC system in comparison to the various problems related to operating a complex system of AC lines and stations with their auxiliary systems, protection and control apparatus, etc.;

d. A substantial reduction of the load on existing 500 kV AC lines; and

e. No impact on the levels of short circuit on existing stations.

In the long-term perspective another potential use of HVDC systems could be to supply large urban areas.

The majority of large city power grids are characterized by high load densities, stringent and ever increasing requirements for reliability, power quality and significant reliance on power imported from outside sources.

Increasing the power delivery to such large urban areas relying solely on the AC expansion option is often limited by various critical issues:

a. The risk of increasing short circuit current beyond critical levels;

b. The possibility of generating widespread disturbances; and

c. The identification of transfer capability limitations and AC network expansion restrictions.

There are various examples available today where an unconventional solution based on direct DC feed-in has been implemented.

Currently a point-to-point HVDC system delivers power directly to inner city load centers (e.g. Cross Sound/330 MW, Neptune/660 MW, Trans Bay/400 MW in New York and San Francisco areas, USA).

Again, it should be noted that the contribution provided by the HVDC link has multiple effects for this specific application:

a. Consistent transmission of power to the thermal limit of the link;

b. Significant stability of the system;

c. Significant increase in the utilization of AC lines belonging to the same nodes;

d. Reduction of congestion on parallel AC lines; and

e. No increase in short circuit levels.

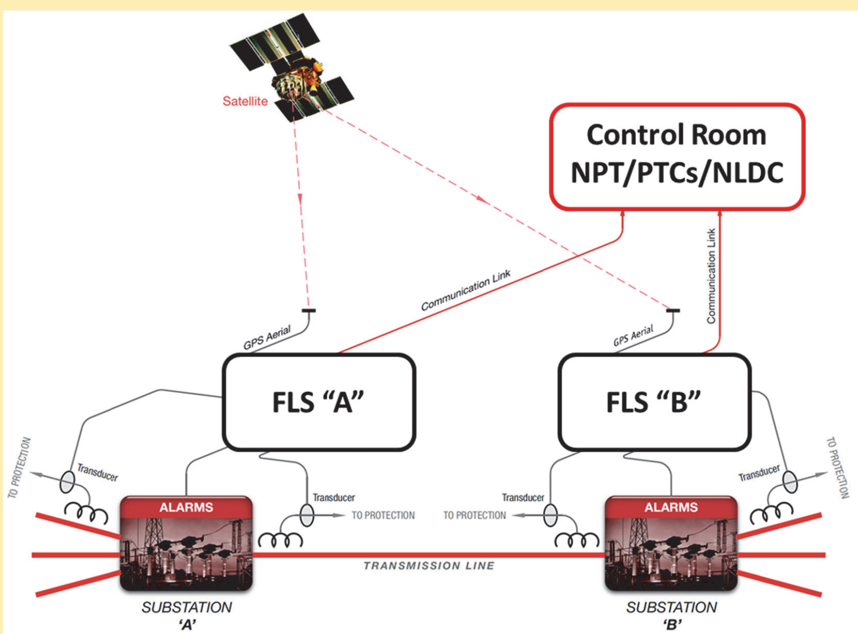
In the previous section 'D.4.4', some details on one of the above mentioned applications, namely the Trans Bay Project example, USA was provided where both the technical and economic benefits i.e. reduction of losses and economic dispatching were also summarized.

F.9 Fault Locator System

One of planned initiatives in the NPT Smart Grid roadmap is the development of a Fault Locator System (FLS). This project is already underway and six of the most important substations of the 500 kV transmission network will be equipped with FLS devices during 2015. Other fault locators will be installed in key substations of the 220 kV network.

Figure 65 depicts the basic components involved in such a system. It can be seen that the data produced by FLS devices will be transmitted to NLDC and NPT remote centers for processing and operation.

FIGURE 65: VIETNAMESE FLS PROJECT



Source: NPT-World Bank, 2013, (18)

This project can be seen as a Smart Grid solution to reduce time and cost of asset maintenance, which has been described as one of the challenges of the Vietnamese transmission system (see 'Annex 2b.x').

In particular, NPT considers its main project objectives as:

a. The reduction of line patrol manpower costs;

b. The prevention of re-occurring faults;

c. The reduction of the impact on power quality of "preventable faults";

d. The reduction of costs to maintain system security during line outage; and

e. The reduction of regulatory fines for power outages.

This system bases fault location on travelling waves for overhead lines and the fault locating devices can find the fault using the transients generated by the fault itself or by using the transients generated by the re-closure of the circuit breaker onto the faulty line after the initial trip.

Using the travelling waves principle the location algorithms of these components, which differ from conventional fault locators based on fault impedance are not affected by fault resistance and so their accuracy level is usually higher. In particular, such accuracy levels are guaranteed by the simultaneous use of the transmission line equations and GPS synchronization. Its precision makes this system extremely useful on long lines.

This system is useful for locating different types of faults (phase-to-ground, phase-to-phase, etc.) and the collection of all data acquired by a remote center can be processed using different techniques. These include the simple double-end methods that do not use data from neighboring substations these algorithms fail if one of the data acquisition devices at either end of a line does not succeed in capturing the fault transient. To avoid this it is possible to implement wide-area travelling wave fault location algorithms, which make use of travelling wave data from various substations across the monitored network.

The level of precision achievable in fault location by such systems can lead to significant improvements in asset maintenance activities and to meet NPT's key performance indicators.

The FLS features make this system a very useful and advanced solution that could benefit the Vietnamese network. However, it is important to consider that all the basic interventions suggested earlier for improvements of the Asset Management and Planning strategies (see paragraph 'E.3.1') are necessary and probably more urgent than FLS implementation.

F.10 Power quality monitoring system

In 'Annex 2b.xi' the improvement of power quality levels is introduced as a challenge for the Vietnamese network. In order to achieve this end the development of a power quality monitoring system is an appropriate Smart Grid application.

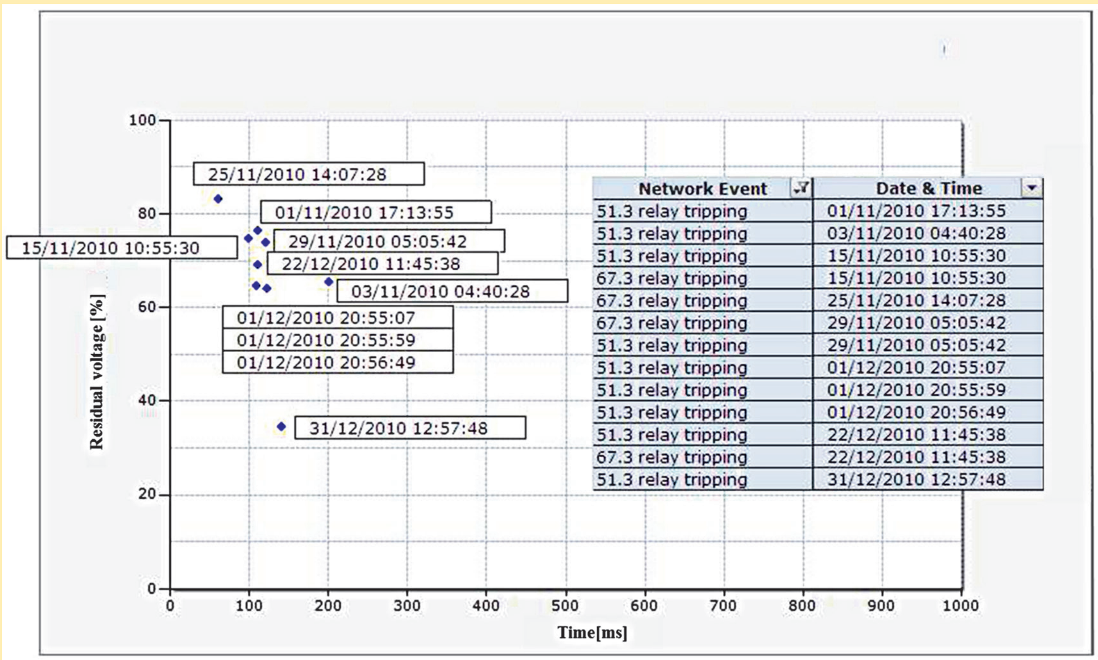
Towards this aim it is fundamental to carry out a device installation activity to cover the most significant points of the transmission network and then to enable the necessary TLC system to collect their data in a central repository. In this way it will be possible to perform measurements to define the expected levels of voltage quality and define practical PQ standards that will apply to all the agencies connected to the transmission network.

Furthermore, thanks to a unique storage system for PQ data it is possible to investigate the real causes of poor PQ events in a manner that can accurately establish whether they originate from the transmission network, the distribution network or the user's installations. Thus, further information will be available to all stakeholders of the Electricity market (such as, customers, regulators, etc.) who have an interest in updating the standards and/or in drafting new agreements regarding PQ key performance indicators ("Quality contracts").

A central management system will allow control center applications to match, compare and post-process all data coming from the smart appliances (network automation and remote control, metering, demand management systems, PQ monitoring, etc.) integrated in the SCADA network. Such analysis will improve the understanding of the actual level of voltage supply characteristics providing more data and information about the causes and propagation of PQ disturbances. For this purpose a large number of measurement points will provide enough data for accurate and relevant statistical analysis leading to meaningful results as the basis for developing new functionalities.

Figure 66 shows an example of correlations between voltage dips and commensurate network events. The blue spots are the voltage dips which correlate with identified network events.

FIGURE 66: CORRELATION DIAGRAM BETWEEN VOLTAGE DIPS AND THE NETWORK EVENTS



Source: Authors

Therefore, PQ analysis provides more data and information about the causes and the propagation of the disturbances which could help to optimize investments in installations to increase resilience to voltage dips or other potentially harmful voltage characteristics.

Finally, international experiences investigated in 'D.2.9', may provide a helpful best practice for the use of PQ data analysis for the assessment of protection systems performance. As stated in 'Annex 2b.viii', miscoordination of the protection systems are one of the main issues highlighted in the Vietnamese transmission network. Towards this end the number of voltage dips and commensurate protection behavior, as seen in Figure 17, could be correlated to identify whether an anomalous number of events correspond to the 2nd step of the distance protections, thus revealing the presence of incorrect settings or malfunctioning processes.

The information about events acquired by PQ monitoring, together with its integration in the other systems just described, can help pinpoint problems and track down their causes.

F.11 On-line Dissolved Gas-in-oil Analysis for Power Transformers

Reliable energy flow is paramount and power transformers whilst critical to ensuring this reliability are quite costly assets in a transmission grid. As an asset type, power transformers constitute one of the largest investments in a utility's system. For this reason transformer condition assessment and management is a high priority.

In several parts of the world the transformer fleet is operating beyond its design life and with higher average loads than ever before. Some statistics on the North American power transformer fleet follow:

a. The average age of power transformers is in excess of 42 years and increasing by 0.6 years per year; and

b. Transformer failure rates, both catastrophic and non-catastrophic, continue to increase.

The cost of replacing enough power transformers to reduce or flatten the growth of the average age is not a cost-efficient alternative for most electrical utilities. This situation demands the best asset management and condition assessment approaches available to optimize the sunk investment in the existing fleet while maintaining reliability to ever higher standards.

Dissolved Gas Analysis (DGA) is recognized as a powerful monitoring technique for the detection of emerging faults within transformer main tanks and associated oil filled equipment. Extensive historical data collected by laboratory analysis over the years is a useful basis for the accurate interpretation of results.

The experience earned in data interpretation is crucial to fully exploit this monitoring technology. Figure 67 shows an example of the analysis of multiple gas trends. The trend graph clearly shows decreasing oxygen and increasing carbon monoxide levels. The presence of carbon dioxide indicates overheating of the paper insulation in the transformer. These trends usually lead to a rapid increase in hydrogen and acetylene indicating an electrical fault. The anomalous trends of oxygen and carbon can be observed about three months before a potentially catastrophic fault event.

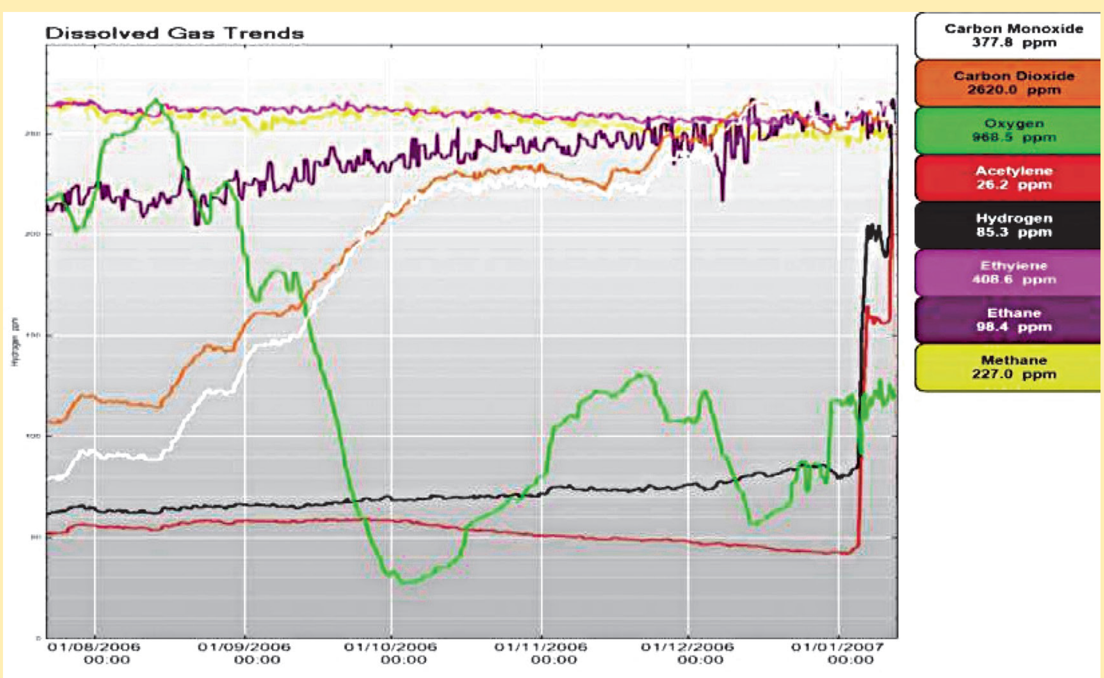
The example demonstrates why on-line DGA has become increasingly relevant for timely fault detection, especially in the context of the ageing worldwide transformer fleet.

In particular, on-line DGA has enabled the monitoring activity to evolve from the collection of infrequent snapshots of transformer conditions in time to understanding the dynamic behavior of gases over the daily operating cycles of the transformer delivering new and previously unavailable insights.

DGA online monitoring systems are another component of the smart maintenance of the network and hence part of a Smart Grid roadmap. This technology is a very effective transformer fault prevention and Asset Management strategy. A Smart approach for managing the maintenance process would collate data from a DGA system with data collected from visual inspections, measurements and operations.

Even though this initiative is not present in NPT's Smart Grid roadmap they have already started a project installing on-line DGA sensors and they anticipate completion for their most critical transformers by the end of 2015. The

FIGURE 67: EXAMPLE OF DISSOLVED GAS TRENDS



Source: General Electric, 2013, (23)

full rollout of such an initiative can be assigned a medium/long term time scale on their Smart Grid roadmap.

A successful deployment of such technology will entail equipping transformers with DGA sensors but a different approach will have to be taken with new transformers.

Whilst no particular analysis has to be performed before installing new transformers it is worth including DGA devices in all of them. This is because the cost of these DGA components is negligible (about 2%-3%) compared to the cost of the whole transformer. The return on investment would be more than sufficient if even one of these monitoring systems per transformer prevented an outage.

On the other hand, the installation of on-line DGA device in old transformers requires a pre-requisite activity to identify the most critical and valuable ones to be protected by this new technology. In most cases DGA monitoring reveals its real added value when consistent historic data collection has been performed. Such devices evaluate on the basis of variations of given parameters, as seen in the example shown in Figure 67, and not on instantaneous values.

It is entirely possible that a transformer that has worked quite reliably for a long period (15-20 years), once equipped with one of these devices reveals anomalous values for some parameters. There are cases where this reveals the existence of a real problem, as in the BC Hydro experience described in paragraph 'D.4.3'. However, in other cases these outliers are false positives i.e. those values, which in general can be considered abnormal for a specific transformer could be totally normal and do not indicate any imminent fault, especially if such parameters remain stable.

Therefore, when old transformers are equipped with DGA sensors, it is essential to perform a careful analysis that combines the new monitoring features with traditional techniques so as to avoid false positives and ensure a set of consistent data to characterize the typical behavior of such transformers.

F.12 Dynamic Thermal Circuit Rating

The real-time monitoring of the network is an important tool at the disposal of TSOs as it will aid the efficient and safe operation of the electrical system. Dynamic Thermal Circuit Rating (DTCR) provides an estimation of the actual loading of the line and indicates by how much the line may be overloaded before incurring premature aging of the conductors. In fact, traditional static line ratings were expressed as the Ampere limits calculated during the project phase and were based on average boundary conditions (e.g. weather conditions) but nowadays they are usually based on the thermal limits of the conductors.

DTCR is based on the calculation/estimation of the conductor temperature in real-time so that calculating the real Ampere limit of the line during existing weather conditions is possible. Furthermore, knowing the present temperature of the conductor is necessary not only to calculate the static Ampere limit of the line but also to estimate how much the line may be overloaded by a specific over-current prior to reaching the thermal limit of the conductor. This goes beyond the estimation of the average current and of the thermal time constant of the line.

DTCR takes into account the real thermal stresses on lines and equipment by making dynamic characterizations of networks limits. A successful implementation of DTCR optimizes use of the transmission lines which is why it is one of the most important applications within the Smart Grid suite.

NPT has quite rightly considered this initiative in its Smart Grid roadmap but it would probably be better to develop it in the medium/long-term and not in the near future. The Vietnamese network is growing very rapidly and the location of the most overloaded lines changes almost daily as a function of the installation of new power plants or other lines. Thus, at the time of writing this report it is very difficult to identify a significant number of lines to be monitored with DTCR. Instead, the development of a DTCR pilot project on a small group of lines (34) could be a good basis for the future use of this application on a large scale and when the rapid growth rate of the network slows down.

The possible steps for a pilot project are to initially test some different DTCR techniques on a small group of lines in order to collect the results and highlight criticalities of these methods and then to use this information to lead to the possible deployment of the technology on a large scale in the medium/long-term. The NYPA experience described in D.4.2.1 may be very helpful in terms of both the small size of the project and the use of different types of DLR devices and techniques.

DTCR methods are based on the estimation of the line temperature in real-time and the subsequent calculation of the residual loading margin. There are two techniques for estimating temperature and they are either by direct measurement or by with algorithms that use electrical quantities as input.

Using the first type of technique calculates the temperature estimation by using a thermal model of the line based on knowledge of weather conditions. However, weather conditions may vary significantly along the line, especially for long connections, so that this method is not always the most accurate. Another common approach is to equip the line conductors with devices that measure the sag and temperature. However, this method is more suited to the estimation on a single critical span rather than on an entire line.

To overcome the limitations of these methods algorithm based calculations using electrical quantities as inputs can be implemented. On this subject a very interesting example is the estimation based on WAMS measurements. This technique consists of the real-time reconstruction of the electrical parameters of the line based on extrapolation from the WAMS measurements. Comparing the realtime values with standard values it is possible to estimate the current temperature of the line with sufficient accuracy to apply it as a mean value along the whole length.

WAMS is one of the Smart Grid initiatives considered earlier (F.5) but if the measurements derived from it are used as inputs for DTCR systems it is important to highlight some concepts. Compared to other applications that could be developed on a WAMS (such as oscillation monitoring, voltage stability monitoring, etc.) the requirements for the inputs of a DLR algorithm are more challenging regarding the precision of the measurements (especially the voltage module) and PMU synchronization. Moreover, the PMU installation plan must consider the lines that have been chosen for the DTCR project as these lines must be equipped with PMUs at both ends.

The best approach is to design a DTCR project that uses all the different techniques proposed. To do this, the first step is to evaluate which lines are most in need of monitoring, selecting the ones that are usually characterized by high current transits or overloading.

Once the target lines have been selected, it is important to know the structural characteristics of the single spans in order to build a thermal model, span by span. This model will uses estimates of weather conditions as inputs to predict the temperature of the lines. To ensure the accuracy of this process it is very important to choose a suitable range of weather forecasts.

The knowledge of the characteristics of individual line spans will be very useful to identify the most critical ones and to equip them with devices dedicated to the direct measurement of sag and temperature. There are different types of devices available on the market and the best way of evaluating their performance is to analyze where they have been successfully deployed around the world and making a selection on the basis of those geographical locations with environmental conditions and line spans comparable with Vietnamese conditions and line spans.

The next step will be the installation of PMUs at both ends of all monitored lines. The measurements they provide will make it possible to use an algorithm for real-time reconstruction of the electrical parameters and consequently for the estimation of line temperature.

Finally a dedicated algorithm has to be implemented to select the final temperature used for the estimation of the time constant of the line. The final temperature will be identified by selecting one of the three or a combination of them on the basis on the reliability of each method which will vary according to data characteristics.

The final objective is to monitor a large number of electric lines to estimate their overload limits in the best possible way and to use these as an inputs of optimal power dispatching algorithms (i.e. OPF). In this way, where the calculated dynamic limits are higher than currently available static ones, it will be possible to relax some of the optimization procedure constraints and define a better dispatching strategy, which leverages the actual line load margins. Figure 68 shows a possible path to develop a DTCR project.

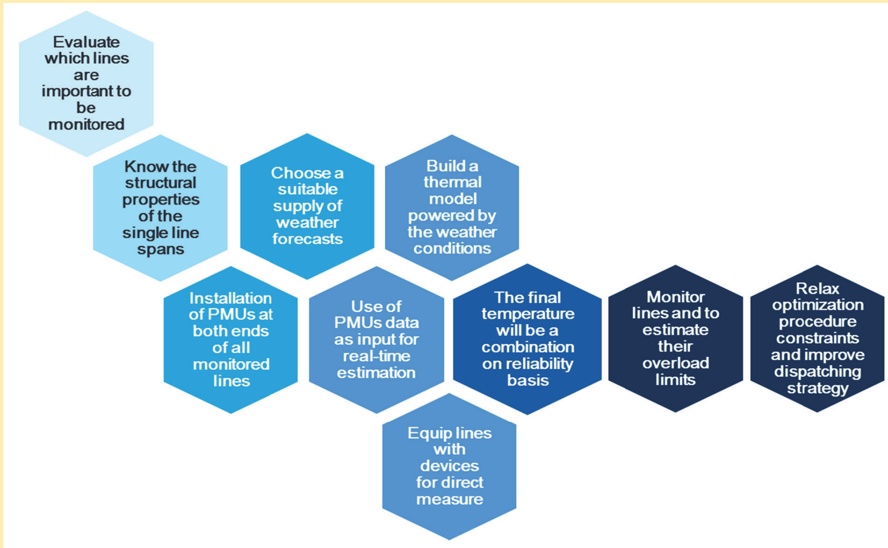
F.13 Geographic Information Systems

In general terms a Geographic Information System (GIS) refers to any application that integrates, stores, edits, analyses, shares, and displays geographic information. GIS tools allow users to create interactive user-created queries on geographical data, link spatial information with external data sources (e.g. load consumption), edit data in maps and present the results of all these operations. Thus, GIS can be integrated with a number of different technologies and/or processes regarding operation, planning, asset management, telecommunications as well as electricity markets.

In their roadmap NPT has considered this project as integrated with the Information System for Asset and Outage Management. An example of the different levels, layers and type of geographical representations being considered are depicted in Figure 69.

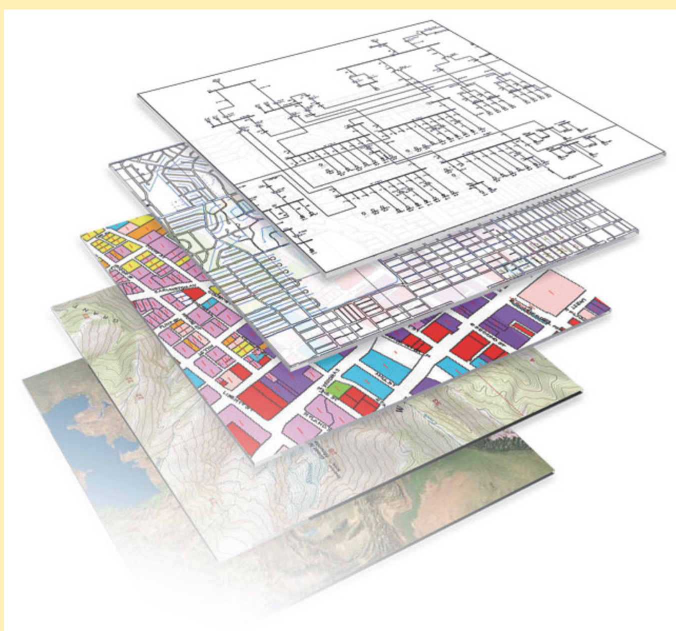
It is worth noting that GIS can embrace a wider scenario. Providing a synthesis which connects the events and measurements with their geographical location is particularly useful for a great number of applications.

FIGURE 68: POSSIBLE DEVELOPMENT OF A DYNAMIC THERMAL CIRCUIT RATING



Source: Authors

FIGURE 69: EXAMPLE OF DIFFERENT LEVELS OF GIS



Source: NPT-World Bank, 2013, (18)

Not only Asset Management but also System Operation functions can benefit from GIS. Most of the initiatives, especially Smart Grid ones, described earlier (like New SCADA/EMS system, WAMS, Lightning Location Systems, etc.) can be developed on the basis of including geographical information as a key point. Therefore, in such an initiative both NPT and NLDC could share geographical information related to the electrical network and its devices.

In order to do this, the first step is deciding those initiatives whose applications could be provided with GIS input and then provide and collect reliable geographical information of all necessary network elements. It is also very important to choose a common data format and a shared policy to archive, update and exchange the geographical information.

In this way the geographical information related to a network element that may prove useful for the different functions of a transmission utility, such as System Operation and Asset Management, will be available to all authorized users. For example PMU and WAMS can be considered as likely candidates. The geographical representation of PMU locations would be fundamental for Asset Management to control their assets and to verify their correct operation. Equally for System Operation, the same information would be an essential input in a geographical representation of WAMS.

GIS cannot be described as a single Smart Grid initiative but needs to be seen as a possible enhancement for other applications. It is appropriate that both NPT and NDLC evaluate the possible added value of the availability of geographical information for all the initiatives they plan to develop. This analysis will drive the implementation of their functions and, over time, provide inputs for new features.

F.14 Metering Data Acquisition System

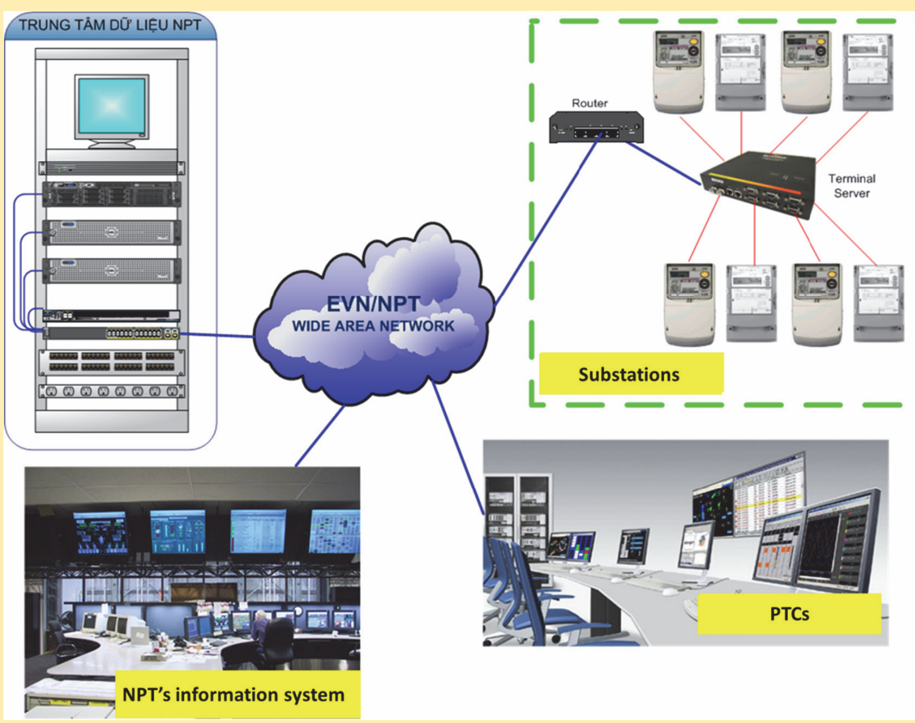
Metering Data Acquisition System is a conventional and mature system widely adopted by several power transmission networks with a mature and functioning open market. A reliable and pervasive measurement system is a key element and an enabling technology for the achievement of an open energy market and for that reason, if no other, it should be included in the roadmap for the Vietnamese Smart Grid.

NPT has already planned such a project and its purpose is to provide an accurate, reliable and real-time measurement of energy consumption and supply at all network points where energy is purchased or sold.

This system is mainly oriented towards market applications aimed at supervising input volumes, net sales and losses. However, the data from the meters could also be used for other applications such as load forecasting, overload prediction, measurement checking and warning of damaged equipment

Figure 70 shows a project overview and it can be seen that, as for the Italian project described in paragraph 'D.2.10', part of the data comes from substations. This

FIGURE 70: METERING DATA ACQUISITION SYSTEM PROJECT OVERVIEW



Source: NPT-World Bank, 2013, (18)

system could benefit from the system improvement developments of the devices and telecommunications for the SAS initiative (described in paragraph 'F.4').

As for other Smart Grid solutions previously discussed, Metering Data Acquisition System requires the installation of monitoring devices that acquire data and a telecommunication system to transmit that data to a central information system.

This project has to deal with a number of technical issues. Due to the acquisition of the measurement problem there is a significant amount of information to process, collate and aggregate regarding data quality, missing data, transmission errors, etc.

Furthermore, this initiative has to deal with regulatory issues due to its relationship with the electricity generation function. The requirement of measurability is the basic condition for the admission of each power plant to the electrical market. There are two fundamental aspects:

a. The accuracy of the measurements available for each power plant; and

b. The identification of the agency responsible for the collection, validation and recording of electrical data.

Such considerations reveal the necessity to develop, at the beginning of the project, a suitable and clear regulatory policy to manage this relationship with the electricity generation function to cope with possible critical situations.

G. Technical Prioritization Analysis and Smart Initiatives Metrics

G.1 Key Points Summary of Technical Prioritization and Metrics

The solutions identified for the NPT Smart Grid roadmap have been prioritized according to three timelines i.e. short term (within 5 years), medium term (within 10 years) and long term (within 15 years).

This time positioning is based on technical prioritization and it is aimed at addressing the pressing and urgent needs as quickly as possible. Therefore, the technical approach used to perform such prioritization is a good starting point for the design of a phased roadmap but it is not exhaustive. The proposed NPT Smart Grid roadmap will be finalized after application-specific cost-benefit and risk analyses and observations related to various regulatory aspects.

The gap analysis performed in chapter 'E' has revealed the strict necessity of implementing some basic enhancements of the transmission system before starting to deploy any Smart Grid technology. The technical requirements definitively position these "**pillars**" in the veryshort term (within 2-3 years) without the need of further evaluations. In the following paragraph 'G.3' a table presenting a brief time positioning and cost estimation of these basic enhancements is proposed.

This chapter also presents the technical reasons for the time positioning of each initiative and some metrics for the evaluation of the success of the various Smart Grid solutions as follows:

a. The key reason for the time positioning of each Smart Grid initiative;

b. The performance indicator for the evaluation of a successful implementation; and

c. The minimum threshold of the performance indicator just mentioned.

The Smart Grid initiatives proposed for the **short term** are the following:

a. **Fault Locator System**:

   i. Reason for positioning in the short-term**:** The NPT project is already underway and is quite independent of all the other initiatives;

   ii. Performance indicator: Reduction of the time taken by maintenance crews to reach the fault location and related outage duration;

   iii. Satisfactory threshold: 25%.

b. **Wide Area Monitoring System**:

   i. Reason for positioning in the short-term**:** Besides the fact that NPT has developed a pilot project, WAMS is a solution that could impact on some of the others and aims to solve a large number of issues;

   ii. Performance indicator: (a) voltage collapse prevention, (b) prevention of out-of-steps collapses;

   iii. Satisfactory threshold: (a) 15%-35%, (b) 15%-35%.

c. **Substation Automation System (building/upgrade of substations and building of Remote Control Centers)**:

   i. Reason for positioning in the short-term**:** This is a NPT project that has already reached a significant level of development;

   ii. Performance indicator: Energy Not Served (ENS) reduction per year for each substation equipped with SAS;

   iii. Satisfactory threshold: 450MWh.

d. **Lightning Location System**:

   i. Reason for positioning in the short-term**:** This is considered as a short-term solution due to the criticality of the lightning problem in Vietnam;

   ii. Performance indicator: Percentage reduction of transient faults;

   iii. Satisfactory threshold: 20%-30%.

e. **Metering Data Acquisition System**:

   i. Reason for positioning in the short-term**:** Metering Data Acquisition System represents the enabling technology for the development of the electricity trading market;

   ii. Performance indicator: Mean square error between the value acquired by the meters and value calculated by the settlement for the same meter;

   iii. Satisfactory threshold: 0.4%-0.8%.

f. **On-line Dissolved Gas-in-oil Analysis**:

i. Reason for positioning in the short-term**:** The main benefits of this technology are presented with recommendations to equip all new transformers with this type of device (starting from the first ones already planned to be installed);

ii. Performance indicator: Prevention of transformer outages;

iii. Satisfactory threshold: 80%.

The Smart Grid initiatives proposed for the **medium term** are the following:

a. **Static Var Compensator**:

i. Reason for positioning in the medium-term**:** It aims to solve the voltage instability problem, which is quite critical, but before installing SVCs a very detailed feasibility study has to be performed;

ii. Performance indicator: (a) 95% (1 σ) variation interval of voltage level of network "pilot nodes, (b) voltage collapse prevention;

iii. Satisfactory threshold: (a) +/-5% of the rated voltage, (b) 15%-35%.

b. **Geographic Information Systems**:

i. Reason for positioning in the medium-term**:** The prior development of other systems like SAS or WAMS could be very useful to plan the implementation of this type of solution;

ii. Performance indicator: Reduction of management costs;

iii. Satisfactory threshold: 10%–15%.

c. **Power quality monitoring system**:

i. Reason for positioning in the medium-term**:** Power Quality is one of the challenges of the Vietnamese transmission system but it is not considered as one of the most critical;

ii. Performance indicator: Reduction of voltage dips;

iii. Satisfactory threshold: 20%.

The Smart Grid initiatives proposed for the **long term** are the following:

a. **High Voltage Direct Current technology**:

i. Reason for positioning in the long-term**:** The interconnection with neighboring countries is not an urgent requirement;

ii. Performance indicator: Increased load factor;

iii. Satisfactory threshold: 0.7.

b. **Dynamic Thermal Circuit Rating**:

i. Reason for positioning in the long-term**:** It would be better to wait for the current rapid growth rate of the transmission network to slow down in order to leverage this application on a large scale;

ii. Performance indicator: "Ampacity" increases;

iii. Satisfactory threshold: 5%–25%.

G.2 Technical prioritization structure

Having collected all the Smart Grid initiatives suitable for the Vietnamese transmission system it is worth analyzing their prioritization from a technical point of view.

In Figure 71 the different solutions have been positioned on the basis of the transmission system issues they aim to solve. Here, thanks to the descriptions of each solution provided in the previous chapter, a strict technical prioritization of the initiatives is performed which describes the reasons for their assignment in the short, medium or long term.

Expanding on the concept of "**pillars**" as a foundation for the Smart Grid, as introduced in section 'E.3', the same idea of construction has been developed in Figure 71, where the schema for the time positioning of the proposed solutions is depicted.

The positioning of the proposed Smart Grid initiatives on different time scales refers to the rollout of these initiatives. The aim of the technical prioritization is to present the priorities and urgent needs which is why there is no indication regarding the time schedule.

Furthermore, it is worth observing that the development of each Smart Grid initiative must not to be considered as an atomic action as full deployment may take a lot of time, but its partial output could enable a useful starting point for other Smart Grid solutions.

The rest of this chapter describes the different "levels" of the construction, highlighting the technical reasons for the time positioning of each initiative and proposing some metrics for the evaluation of the success of the various Smart Grid solutions.

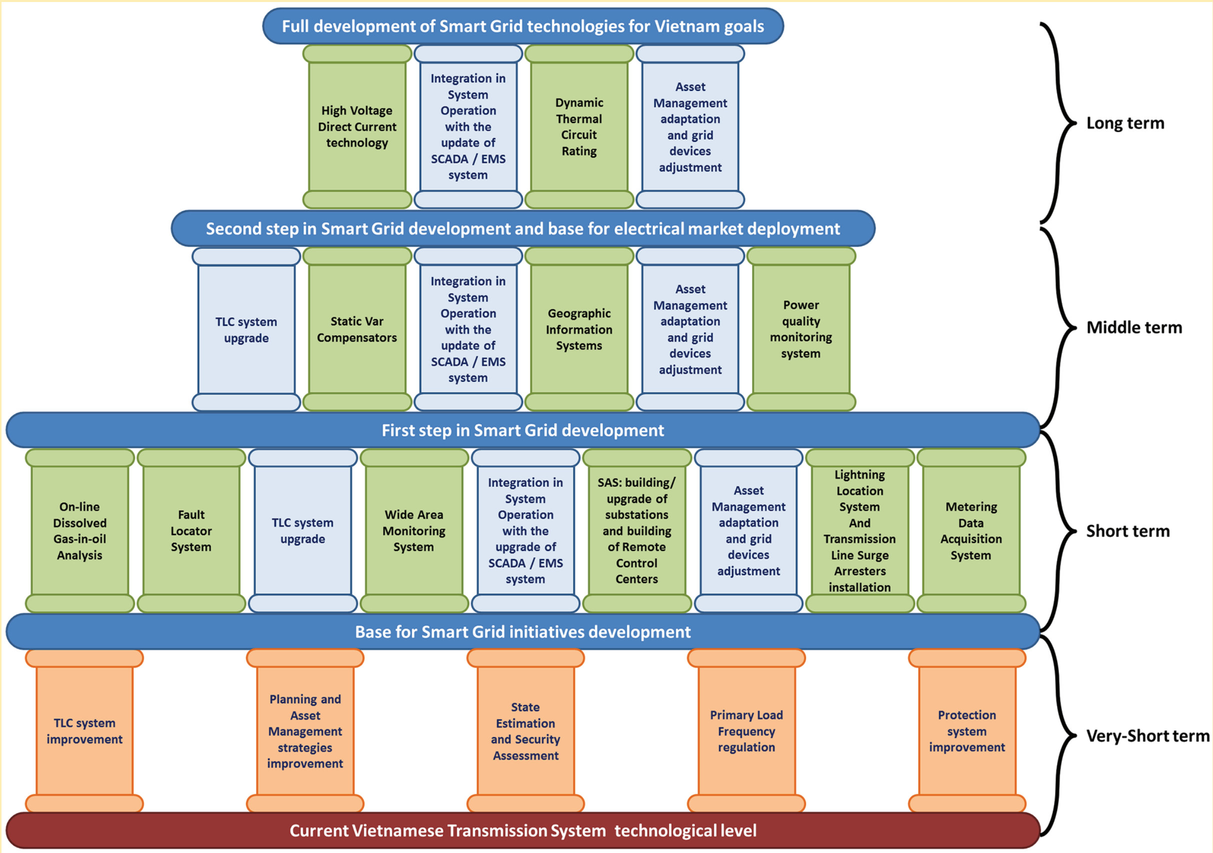
The pillar-based approach is divided into four "levels":

a. Very-Short term (within 2-3 years);

b. Short term (within 5 years);

c. Medium term (within 10 years); and

FIGURE 71: TECHNICAL PRIORITIZATION AND REFINED SMART GRID ROADMAP



Source: Authors

d. Long term (within 15 years).

All the Smart Grid solutions are represented by green pillars, while the development of traditional technologies needed to underpin the upper levels are shown in light blue.

These pillars have been introduced because, as stated in chapter 'F', the majority of the Smart Grid initiatives require parallel developments of many other systems for support and/or integration with new technologies. A case in point is the example of the investments in the TLC system necessary for the full development of SAS or WAMS (see 'F.4.3' and 'F.5.3').

G.3 Time positioning of Transmission System enhancement interventions

To reach an adequate technological level in the Vietnamese transmission system for enabling Smart Grid development a "**Transmission System enhancement**" is necessary. The gap analysis, performed in chapter 'E', has identified the following basic building blocks (or "**pillars**") as fundamental:

a. Planning and AMS basic strategies improvements;

b. State Estimation and N-1 Security Assessment;

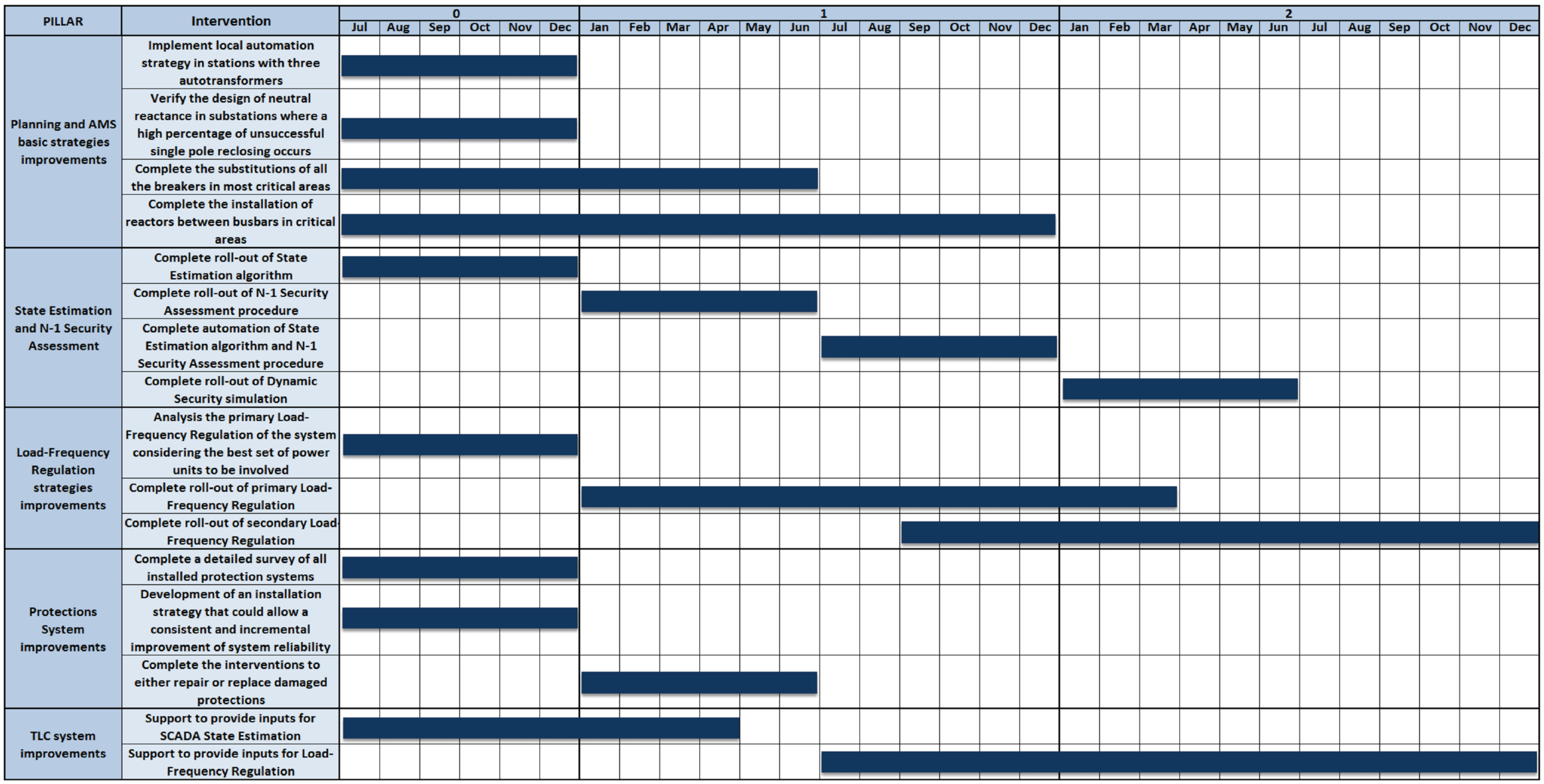
c. Load-Frequency Regulation strategies improvements;

d. Protection Systems improvements;

e. TLC system improvements.

The aim of this section is to detail the concepts shown in Figure 46 proposing a time positioning of these basic interventions and so planning the necessary "**Transmission System enhancement**" before starting the deployment of Smart Grid technologies. Figure 72 presents the different developments (detailed in paragraph 'E.3') regarding the various "**pillars**" on a hypothetical timeline.

FIGURE 72: TRANSMISSION SYSTEM ENHANCEMENT INTERVENTIONS TIME POSITIONING



Source: Authors

This time positioning is a brief guideline based on the information collected during the discovery activity and the missions in Vietnam. These developments do not require any preliminary activity and can start immediately. The time duration of the implementation process of the different developments is a conservative estimation, based on similar activities performed in other countries (e.g. Italy). It could happen that such time durations will be less than stated as some initiatives have already been planned or are underway.

Such time positioning is complemented by a general estimation of associated costs, based on the information gathered and reliable assumptions regarding the Vietnamese transmission system.

Toward this end, Table 15 presents the cost estimation of the Transmission System enhancement developments, highlighting the assumptions made. It is worth underlining that for some initiatives no costs are needed. In these cases the proposed enhancements do not require real investments.

TABLE 15: TRANSMISSION SYSTEM ENHANCEMENT INTERVENTIONS COST ESTIMATION

PILLAR	INTERVENTION	COST ESTIMATION
Planning and Asset Management System basic strategies improvements	Implement local automation strategy in stations with three autotransformers	Negligible in the context of the initiatives already underway for setting-up substation automation systems.
	Verify the design of neutral reactance in substations where a high percentage of unsuccessful single pole reclosing occurs	Negligible in the context of the current work in progress on network maintenance activities.
	Complete the substitutions of all the breakers in most critical areas	The swapping of 30 breakers (at critical points) at a cost of $10,000 each results in a total spend of $300,000.
	Complete the installation of reactors between busbars in critical areas	The installation of 20 reactors at a cost of $40,000 each results in a total cost of $800,000.
State Estimation and on-line N-1 Security Assessment	Complete roll-out of State Estimation algorithm	Negligible in the context of the initiatives already underway for setting-up a new EMS system.
	Complete roll-out of N-1 Security Assessment procedure	Negligible in the context of the current work in progress on setting-up a new EMS system.
	Complete automation of State Estimation algorithm and on-line N-1 Security Assessment procedure	Total cost of $300,000 considering both software purchase and operator training program.
	Complete roll-out of Dynamic Security simulation	Total cost of $300,000 considering both software purchase and operator training program.
Load-Frequency Regulation strategies improvements	Analysis of the primary Load-Frequency Regulation of the system considering the best set of power units to be involved	Total cost of this survey activity is estimated at $200,000.
	Complete roll-out of primary Load-Frequency Regulation Complete roll-out of secondary Load-Frequency Regulation	For hardware and software installation the expense can vary from $30,000 to $60,000 for each power plant. Assuming installation in 40 power plants, the total cost would be between $1,200,000 and $2,400,000.

(Continued next page)

TABLE 15 (CONTINUED)

PILLAR	INTERVENTION	COST ESTIMATION
Protections System improvements	Complete a detailed survey of all installed protection systems	Negligible in the context of the current work in progress on maintenance activities.
	Development of an installation strategy that could allow a consistent and incremental improvement of system reliability	Installing dual protection on 30% of lines at an average cost of $5,000 each results in a total cost of $1,500,000.
	Complete the interventions to either repair or replace unsuitable or damaged protections	Repairing 5% of protection systems at an average cost of $3,000 each results in a total cost of about $150,000. Replacing 5% of protection systems at a cost of $5,000 each results in a total cost of $250,000.
TLC system improvements	Support to provide inputs for SCADA State Estimation Support to provide inputs for Load-Frequency Regulation	Negligible in the context of the current work in progress on setting-up the telecommunication infrastructure.

Source: Authors

G.4 Reasons for technical prioritization and metric identification

The first "level", named "*Base for Smart Grid initiatives development*", rests on the five "**pillars**" described in paragraph 'E.3'. Upon this "level" or base it will be possible to begin developing in the **short-term** the following Smart Grid initiatives:

a. **Fault Locator System**. The NPT project is already underway and is quite independent of all the other initiatives. It can contribute to time and cost reduction of asset maintenance of the most critical areas of the network with a relatively few number of components. In order to evaluate the success of the FLS initiative, it is worth measuring the reduction of the time taken for maintenance crews to reach the fault location and related outage duration. The FLS application can be considered satisfactory if after its implementation such times are reduced by 25%.

b. **Wide Area Monitoring System**. Besides the fact that NPT has developed a pilot project, WAMS is a solution that could impact on some of the others (e.g. Dynamic Thermal Circuit Rating) and aims to solve a large number of issues (e.g. voltage and transient stability, defense plans, etc.). The evaluation of the success of WAMS initiative can be very complex and it is strictly dependent on the functions developed using PMU data. For example, the evaluation of a voltage stability-monitoring feature based on WAMS can be considered successfully implemented if it helps to prevent 15%-35% of voltage collapses. The percentage depends on the topology of that portion of the network involved in the voltage instability events. The evaluation of a transient stability monitoring function on WAMS can be considered successfully implemented if it helps to prevent 15%-35% of power plants out-of-steps. As in the voltage collapse case, the percentage depends on the topology of the portion of the network involved.

c. **Substation Automation System (building/upgrade of substations and building of Remote Control Centers).** This is a NPT project that has already reached a significant level of development. It has been conducted in synergy with building of Remote Control Centers for unmanned substations since Remote Control Centers constitute a pre-requisite to exploit at best SAS equipment in electrical substations. Their realization is fundamental to position such SAS initiative in the short term. In order to support remote control the development of a communication backbone connecting all the substations under NPT management is a fundamental requirement. The status of the deployment to date is discussed and some recommendations are made in order to optimize the benefits of this solution, especially with regard to interoperability and prerequisite telecommunication system improvements. Fully digitalized substations, remote terminal units, remote operation and supervision represent the key elements for the success of SAS initiative. As described in the international experiences section (see section 'D.2.6'), the key performance indicator (KPI) for the evaluation of this application is the reduction of Energy Not Served (ENS). A SAS implementation can be considered successful if the average value of annually prevented faults per substation equipped with SAS is above 1.5. Considering an average value of 300 MWh of load losses per fault event, this value corresponds to an average ENS reduction of 450 MWh per year for each substation equipped with SAS.

d. **Lightning Location System**. This is considered as a short-term solution due to the criticality of the lightning problem in Vietnam. Furthermore the installation of a Lightning Location System requires quite a long lead time which is why, if the proposed solution is approved by NPT, it should begin as soon as possible. After Transmission Surge Line Arresters installation (guided by Lightning Location System data analysis). The KPI of the initiative is a reduction of faults in the range of 20%-30% which would be considered satisfactory.

e. **Metering Data Acquisition System.** The NPT project is already underway and it is important to reach a full rollout of this initiative in the near future because it represents the enabling technology for the development of the electricity trading market. The simultaneous installation of SAS may be useful for facilitating the data acquisition process of the Metering Data Acquisition System. It is worth to consider that for the full deployment of such initiative a careful investigation of all the regulatory aspects is fundamental. To evaluate the success of the Metering Data Acquisition System initiative it is worth measuring the mean square error between the value acquired by the meters and the value calculated by the settlement for the same meter. A satisfactory value would lie in the range 0.4%-0.8%.

f. **On-line Dissolved Gas-in-oil Analysis**. It is proposed that all new transformers have this device installed, as its cost is about 2-3% of the value of the transformer it protects and no particular analysis has to be performed before installing this equipment on new transformers (as mentioned in paragraph 'F.11'). Furthermore, NPT is already started to develop this initiative and it is worth to continue investing in this type of technology on all the transformers that will be installed in Vietnam in the next years. Therefore this initiative has been positioned in the short term. On the other hand, their use with the existing transformer fleet instead will require the identification of the most critical and valuable ones that need to be protected. In fact equipping current transformers with these monitoring devices requires a detailed investigation in order to evaluate the time needed to gather data for the characterization of typical transformer behavior so as to eliminate false positives. The DGA installation initiative can be considered successful if using these monitoring systems a consistent prevention of transformer outages is achieved. A satisfactory value is a reduction by 80% in the number of faults.

The "*First step in Smart Grid development*" will have been reached following the development of the projects described above. Upon this "level" it will be possible to begin developing in the **medium-term** the following Smart Grid initiatives:

a. **Static Var Compensator.** This aims to solve the voltage instability problem, which is quite critical, but before installing SVCs a very detailed feasibility study has to be performed. Making the right choice regarding the locations of SVC devices in a fast growing network like the Vietnamese one will prove to be really challenging. To evaluate the SVC installation performance it is imperative to measure the variations of voltage level of the most important network nodes (called "pilot nodes"). If 95% (1 σ) of such variations is within +/-5% of the rated voltage the result can be considered satisfactory. Furthermore, as for WAMS evaluation, a SVC can be considered to be operating successfully if it helps to prevent 15%-35% of voltage collapses in the portion of the network influenced by its effects.

b. **Geographic Information Systems**. The prior development of other systems like SAS or WAMS could be very useful to plan the implementation of this type of solution considering the largest possible number of applications that would benefit from this initiative. In order to evaluate the success of the GIS initiative, it is worth measuring the reduction of management costs of the network. A satisfactory value for such reduction would be in the range of 10%–15%.

c. **Power quality monitoring system**. Power Quality is one of the challenges of the Vietnamese transmission system but it is not considered as one of the most critical. A suitable KPI is the percentage reduction of voltage dips where a value above 20% can be considered satisfactory.

The "*Second step in Smart Grid development*" will have been reached by this stage and with the implementation of the Metering Data Acquisition System the base for the electrical market deployment will have been created. Upon this "level" it will be possible to begin developing the **long-term** Smart Grid initiatives as follows:

a. **High Voltage Direct Current technology**. It is worth developing this type of technology, which could be useful for the interconnection with neighboring countries. This topic is not urgent and HVDC represents one of the possible solutions to be evaluated but is not the only possibility. To evaluate the success of an HVDC link installation it is worth measuring its load factor and a value above 0.7 can be considered satisfactory.

b. **Dynamic Thermal Circuit Rating.** NPT has already planned the development of such an application, so the implementation of a pilot project will be a good starting point. However, it would be better to wait for the current rapid growth rate of the transmission network to slow down in order to leverage this application on a large scale. According to international experience the dynamic ratings are typically 5% to 25% higher than conventional static ratings. So, if on the lines where the DLR is applied the "ampacity" increases from 5% to 25% the results of DLR implementation will be considered satisfactory.

The "*Full development of Smart Grid technologies for Vietnam's transmission system goals*" will have been reached following the development of the initiatives described above.

All of the above has to be considered as a technical prioritization of the Smart Grid initiatives and that the process of positioning the solutions on the timeline was evaluated on the basis of whether:

a. A similar project is already ongoing even as a pilot project (e.g. Substation Automation System or Wide Area Monitoring System);

b. A project is a prerequisite for other ones (e.g. a full Substation Automation System implementation as a useful base for Metering Data Acquisition System development); and

c. The urgency of the transmission problems that a project aims to solve is high or low (e.g.: Lightning Location System).

This technical approach is a good starting point for the design of a phased roadmap but it is not exhaustive. Thus, at the time of this report it is too early for the full development of a precise GANTT of the implementation plan without having the results of the Cost-Benefit Analysis, which evaluates some possible development scenarios of the proposed initiatives and the installation times.

The final prioritization of the Smart Grid initiatives will be defined after the Cost-Benefit Analysis, which will also evaluate the economic parameters in order to understand the real added value of each solution.

Finally, the metrics identified for the evaluation of the success of the various Smart Grid solutions is a good starting point for the Cost-Benefit Analysis because it will be exploited for evaluating the benefits of the initiatives. The performance indicators proposed for each application are summarized in the following Table 16.

It is important to note that these metrics consider the Smart Grid solutions only from the technical point of view. The complete list of KPIs will be proposed in the third report, after the evaluation of Cost-Benefit Analysis results.

TABLE 16: TECHNICAL METRICS IDENTIFIED FOR SMART GRID SOLUTIONS

SMART GRID SOLUTION	PERFORMANCE INDICATOR	SATISFACTORY THRESHOLD
Fault Locator System	Reduction of time taken to attend fault site by maintenance crew and related outage duration	25%
Wide Area Monitoring System	Voltage collapse prevention	15%-35%
	Out-of-steps prevention	15%-35%
Substation Automation System	Energy Not Served (ENS) reduction per year for each substation equipped with SAS	450MWh
Lightning Location System	Percentage reduction of transient faults affecting the lines	20%-30%
Metering Data Acquisition System	Mean square error between the value acquired by the meters and the calculation by the settlement process for the same meters	0.4%-0.8%
Static Var Compensator	95% (1 σ) variation interval of voltage level of network "pilot nodes"	+/-5% of the rated voltage
	Voltage collapse prevention	15%-35%
Geographic Information Systems	Reduction of management costs	10%-15%
Power quality monitoring system	Percentage reduction of voltage dips	20%
High Voltage Direct Current technology	Load factor	0.7
On-line Dissolved Gasinoil Analysis	Reduction in the number of faults	80%
Dynamic Thermal Circuit Rating	"Ampacity" increase	5%-25%

Source: Authors

Annex 1. Functional and Organizational View of Transmission Systems Worldwide

In order to implement the Smart Grid initiatives in the most efficient way, it is important to define the functions central to an Electricity Transmission System and the viable models for the organizational structure of the transmission operators. This approach will make it possible to identify the various contributors to the transmission system and to understand their interactions within the context of the selected Smart Grid applications.

In general terms, it is important to note that a transmission company may assume the role or roles as follows:

a. System Operator of the network;

b. Asset Manager of the grid; and

c. Both the above roles.

The transmission systems worldwide are organized in different ways depending on the specific market structures of the country under consideration:

a. In the **USA**, there is Regional Transmission Organizations (RTO) to manage the transmission grid on a regional basis throughout North America (including Canada). FERC Order No. 2000 delineated twelve characteristics and functions that an entity must satisfy in order to become a Regional Transmission Organization.

b. In **Europe** there are Transmission System Operators (TSO) which are entities entrusted with transporting energy on a national or regional level, using fixed infrastructures. The term TSO was defined by the European Commission. The certification procedure for Transmission System Operators is listed in Article 10 of the Electricity and Gas Directives of 2009.

c. In several **Latin American** countries, the transmission operators have different functions according to the market, which range from the transmission activity to planning and investing.

This divergence leads to different naming conventions for the companies depending on their specific chosen function. In order to avoid misunderstandings in the following sections, the term "*transmission utility*" will be used as a generic reference for companies that manage a transmission system.

In this chapter the structure of different kinds of transmission utility will be analyzed both from the functional and organizational point of view. In the first place it is important to identify all their functions and the definitions provided by CEER (Council of European Energy Regulators) best describe these functions (see [27]).

The CEER model is the European benchmark for electricity transmission system operators and this approach has been chosen because it offers a complete description of transmission utility duties and supports the introduction of the principal organizational structure models. Furthermore, reviewing the functional view of a transmission system in the light of the European experience could be a useful point of reference for the Vietnamese experience.

a. Functional View of Transmission Systems

A transmission utility has the fundamental duty to ensure the stability of the electrical system (either interconnected or not), in order to guarantee that energy can be transmitted from generators to distribution networks.

The basic assignments of a transmission utility are:

a. The provision of open access to the transmission system;

b. The monitoring and control of the system operations in order to ensure energy balance, congestion management and generation scheduling;

c. The acquisition of ancillary services, such as disturbance reserves and voltage support; and

d. The planning and the approval of the requests for maintenance of the transmission and generation facilities.

CEER distinguishes six important functions or roles, these are:

a. Market Facilitation;

b. System Operation;

c. Grid Planning;

d. Grid Construction;

e. Grid Maintenance; and

f. Grid Ownership/Financing.

The first function is performed in those countries with a well-developed electricity market. In these cases system operators administer spot and real-time balancing of energy markets. These operators generally also carry out metering, accounting, settlement, and billing for the markets, but may additionally initiate, enforce or administer market instruments related to congestion management, supply safety and load control.

Then, there are System Operation and Grid Planning, which are strategic and have both a real-time and long-term impact on system performance. On the other hand, the functions of Grid Construction and Maintenance are typically also identified as Asset Management. However, Grid Ownership is normally connected to regulatory and institutional practices.

a.i. Market Facilitation

The activities for this function involve gathering and collating information regarding costs and direct resources related to the management, facilitation or administration of marketplaces. These include:

a. Measurement;

b. Calculation and dissemination of price tariffs (node prices, price zones);

c. Preparation of annual surveys and forecasts for use by the market's current and potential players and to illustrate compliance with public service obligations;

d. Information for settlement of claims and contract flows from exchanges;

e. Backup agreements; and

f. Research and development into market functioning, mechanisms and contracts.

Market facilitation may also include the responsibilities related to the flow of information to relevant markets (green certificates, renewable fuels, DSM, DER, preferential feed-in tariffs).

Costs and revenues related to transitional or permanent retail engagements, such as procurement, billing, losses and resale of energy are considered specific cases of market facilitation.

a.ii. System Operation

System operation functions have to:

a. Ensure real-time energy balance;

b. Manage congestion;

c. Schedule and dispatch generation;

d. Perform failure analysis and detection;

e. Manage the availability and coordination of preventive and reactive remedial actions; and

f. Acquire ancillary services, such as primary/secondary load-frequency regulation reserves and VAR/voltage support.

All of these duties are aimed at maintaining the technical quality and balance within a coherent electricity supply system and for ensuring that the necessary supply capacity for the regulation of the system is available.

System Operation also has to deal with the limitations of the existing grid, the daytoday management of network functionality (including personnel safety and equipment security), coordination with operations management of neighboring grids, coupling and decoupling in the network of all the players acting on the "live" grid.

a.iii. Grid Planning

This function is aimed at carrying out the analysis, planning and drafting of grid expansions and network installations and includes the management of all the necessary internal and external human and technical resources.

Moreover, grid planning is responsible for system-wide coordination and enhancing the general competence of the TSO. This function has also to take into account costs for research, membership of research organizations and sector organs, development and testing (related to functioning of the transmission system), coordination with other grids and stakeholders.

a.iv. Grid Construction

The grid constructor has the duty to implement the plans originating from the grid planning function. This duty involves tendering for construction and procurement of material, interactions, monitoring and coordination of contractors or own staff performing ground preparation, disassembly of existing installations (if required), temporary site constructions and installations, installation of equipment and infrastructure. In particular, all expenses related to site selection and environmental impact analyses are classified as grid construction costs, since they normally arise during the commissioning.

a.v. Grid Maintenance

The Grid Maintenance function involves all the preventive and reactive services concerning the assets, the staffing of facilities and the replacement of degraded or faulty equipment. Both planned and required maintenance are included, as well as the direct costs of time, material and other resources to maintain grid installations. It also includes field assessment and reporting on the actual condition of equipment and their management, planning of operations and of data-collection/evaluation, lawn mowing, tree cutting and any required emergency actions.

a.vi. Grid Owner/Financing

The grid owner is the possessor of the transmission grid and its function is to ensure the long-term cost efficient financing of the network assets and to administer all the cash flows related to their management.

b. Organizational View of Transmission Utilities

There is a continuing debate about the best model for organizing the coordination and control of the transmission system, including dispatch and coordination of energy balancing or spot markets. This section describes various possible structures highlighting their strengths and weaknesses.

The main types of companies that might be included within a transmission utility structure are [28]:

a. A **full-service TSO**, known as **Transco** in the US, is an independent company that combines ownership of the grid and responsibility for system operations of the grid. It may be a for-profit or not-for-profit entity.

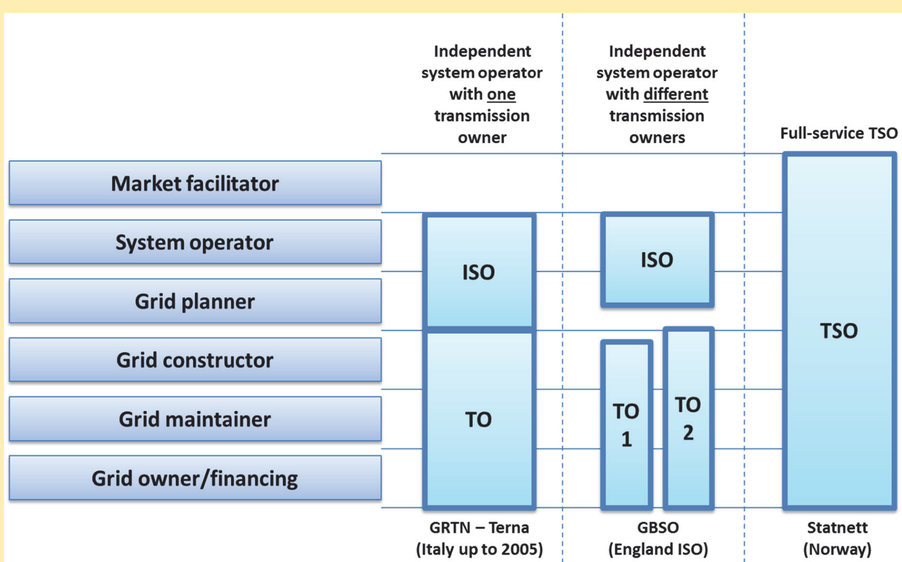
b. A **Transmission Owner** (**TO**), known as **Gridco** in the US, is an independent company that owns the grid, but does not have responsibility for operating the system. It works in conjunction with a system operator and it too may be a for-profit or not-for-profit entity.

c. An **Independent System Operator** (**ISO**) has responsibility for managing the use of the grid and coordinating the spot market.

All the types of companies identified do not have the ownership of generation and retail supply. The ownership separation of TO/ISO from generation and distribution aims to eliminate potential conflicts of interest.

Figure 73 shows the three most significant models of organizational structure; it indicates the transmission utility functions performed by each type of company and identifies a European example of each of them that exploits such a model.

FIGURE 73: TRANSMISSION SYSTEMS: FUNCTIONS AND ORGANIZATIONAL MODELS



Source: e3GRID, 2009, (24)

In the **full-service TSO** model SO and TO functions are under common ownership/control. In this configuration transmission is a monopolistic service, so both it and its prices must be regulated. Regulation of the transmission provider is a substitute for competition, and therefore, its core objective is to prevent the transmission provider from charging customers a price for access and use that would be uncompetitive in an open deregulated market model. This structure is typically combined with transparent organized public markets for energy, network support services and congestion management that are used by the transmission utility to fulfill their responsibilities.

In theory this represents the ideal model. The economics of transmission investment and the scope and scale economies of service provision ensure that this will be the case for the foreseeable future. Furthermore the existing examples of such a model have functioned well in all dimensions.

The main strength is the complete integration of all the Transmission Utilities function that in most cases facilitate the development of applications in which both TO and SO functions are deeply involved.

On the other hand, it requires well-developed **regulatory mechanisms** and may require some functional separation especially in cases where there are unregulated lines of business (e.g. interconnections).

Instead, a **separate ISO** owns the control room and communications facilities and it is independent from all market participants, transmission and distribution owners.

It is responsible for all aspects of reliable and economical system operations and interconnection and may cover facilities of **multiple transmission network owners** (some vertically integrated). Moreover, it is typically integrated with the operation of organized wholesale markets for energy, frequency regulation and operating reserves and is responsible for ensuring that the operations are both economical and reliable.

The presence of a separate **ISO** is naturally required when there is more than one TO and in general it is considered more politically acceptable compared to a **full-service TSO.**

On the other hand, the responsibility for the integrated planning of transmission investments is increased in a separate **ISO**. International experiences demonstrate that ISOs with "deep functional" responsibilities that are well integrated with wholesale markets work reasonably well, but it is really challenging as inefficiencies from the absence of vertical integration with TO functions can lead to problems with coordination of maintenance and investment planning and complicates the governance and regulation of the ISO. In this scenario the responsibilities of the ISO tend to expand over time to deal with these inefficiencies and TOs become passive owners of regulated assets that march to the ISOs orders.

These weaknesses are the reason why the **full-service TSO** represents a reliable future scenario for those countries in which there is **only one TO** and the presence of a separate **ISO** in not compulsory. In this case the example of the evolution that took place in Italy in 2005 is significant. At the time the Italian TSO passed from a structure composed of GRTN (SO) and Terna (TO) to a single full-service TSO (Terna) within which the market facilitation function was subsequently managed by a single entity. The changes to the organizational structure and the development of the Italian transmission system will be described in paragraph 'D.2.1', together with the motivations for such an evolution.

Annex 2. Vietnamese Transmission System

The previous chapter examined a model for the structure of a transmission utility, so, before dealing with the analysis of the Vietnamese issues and challenges (investigated in 'Annex 2b'), it is worth analyzing the organization of the Transmission System in Vietnam in the light of the principles discussed in the preceding sections. In the following section, this analysis will be important to describe the roles played by the different functions of the utility in implementing projects for Transmission System Enhancements and Smart Grid initiatives.

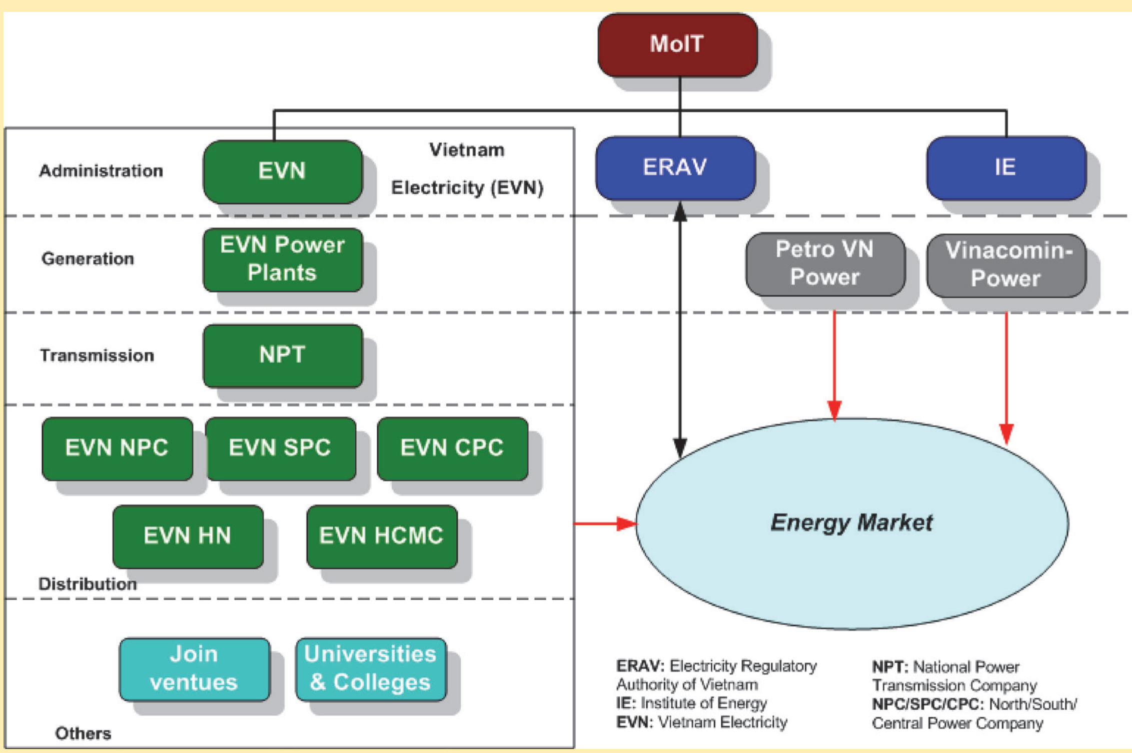
a. Vietnamese Transmission System Organization

Figure 74 [29] shows the roles and relationships of the most relevant players in the implementation of the Vietnamese Smart Grid initiatives.

All energy relevant institutions are headed by the Ministry of Industry and Trade (MOIT) which has the role of policy maker for the whole national power sector and stands above all other relevant energy agencies and generation systems. It is responsible for the advancement, promotion, governance, regulation, management and growth of the electrical industry in Vietnam.

Directly dependent on the Ministry of Industry and Trade there is the Institute of Energy (IE), which is the main organization doing research and contributing to the national energy policy. Its main contributions are studies on national energy strategies, policies and development plans and consulting activities on the formulation of national strategies and policies on energy and power development. Among all the plans prepared by IE there are:

FIGURE 74: VIETNAMESE ENERGY RELATED ORGANIZATION



Source: Annex POWER, 2013, (25)

a. The National Energy Development Master Plan;

b. Monitoring and assessment of Power Development Master Plan implementation process, as Advisor to Ministry of Industry and Trade on steering measures;

c. Preparation of National Power Development Master Plan;

d. National Renewable Energy Development Master Plan;

e. Human resource development plan for the energy sector;

f. Power development plans for territories, provinces, cities, industrial zones and residential areas throughout the country and foreign countries in the region;

g. Plans for grid-connection of power plants, power transmission lines, interconnection with power systems of neighboring countries;

h. Development plans for thermal power, hydropower and nuclear power;

i. National rural electrification master plan; and

j. Research on compiling procedures and norms to serve energy sector development.

These duties highlight the key role in the planning function exerted by the IE within the structure of the Vietnamese Transmission System. In the following sections, when referring to the planning function for the implementation of Smart Grid initiatives it will be important to take into account the strategic role of the IE.

The Electricity Regulatory Authority of Vietnam (ERAV) was established in October, 2005 as an entity under MOIT, to conduct:

a. Development and regulation of power markets;

b. Economic regulation (electricity pricing);

c. Monitoring supply/demand balance to promote security, efficiency and conservation; and

d. Licensing and Dispute resolution.

Then there is the Vietnam Electricity (EVN), which is the main business unit of the Vietnam Electricity Group and includes:

a. Production, transmission, distribution and trading of electricity;

b. Administration of power production, transmission, distribution in the national electricity system; import and export of electricity;

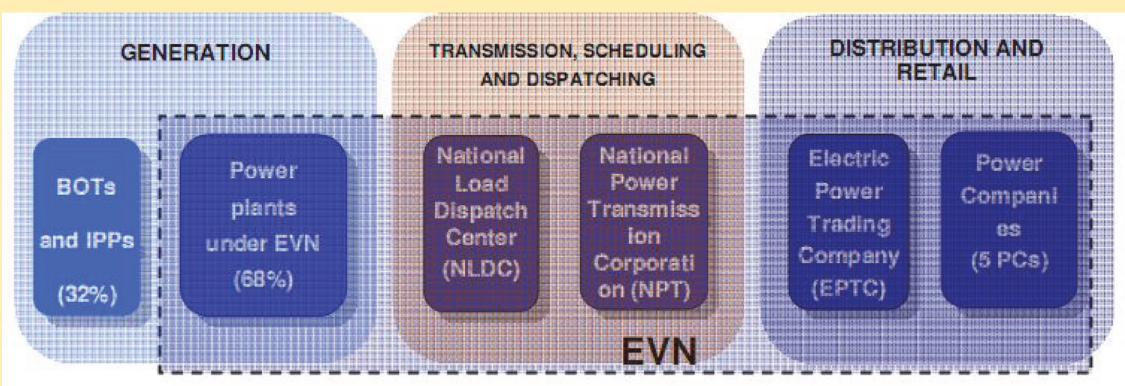
c. Investment management and investment power projects; and

d. Management, operation, repair, maintenance, overhaul, renovation, upgrading of electrical equipment, and electrical research and experiments.

EVN structure (depicted in Figure 75) is characterized by a vertical integration of Generation, Transmission and Distribution.

The two companies that comprise the transmission level deserve particular attention out of all the different EVN structural components and they are:

FIGURE 75: THE VERTICAL-INTEGRATED STRUCTURE OF VIETNAMESE ENERGY SECTOR



Source: Annex POWER, 2013, (25)

a. The National Power Transmission Corporation (NPT), which was established through the merger and reorganizing of four transmission companies and three project management boards. Its main role is Asset Management and in this regard it is responsible for installation, maintenance and control of all the equipment of the transmission network.

b. The National Load Dispatching Center (NLDC) is mainly concerned with System Operation. NLDC is responsible for dispatching of generation, managing congestion, performing failure analysis and detection, controlling availability and coordination for preventive and reactive remedial actions. It is important to underline that NLDC, unlike NPT, has no direct control over the transmission network. Therefore, all actions determined by system operation functions cannot be executed directly, but must be communicated to the NPT, which then performs them on the real transmission system.

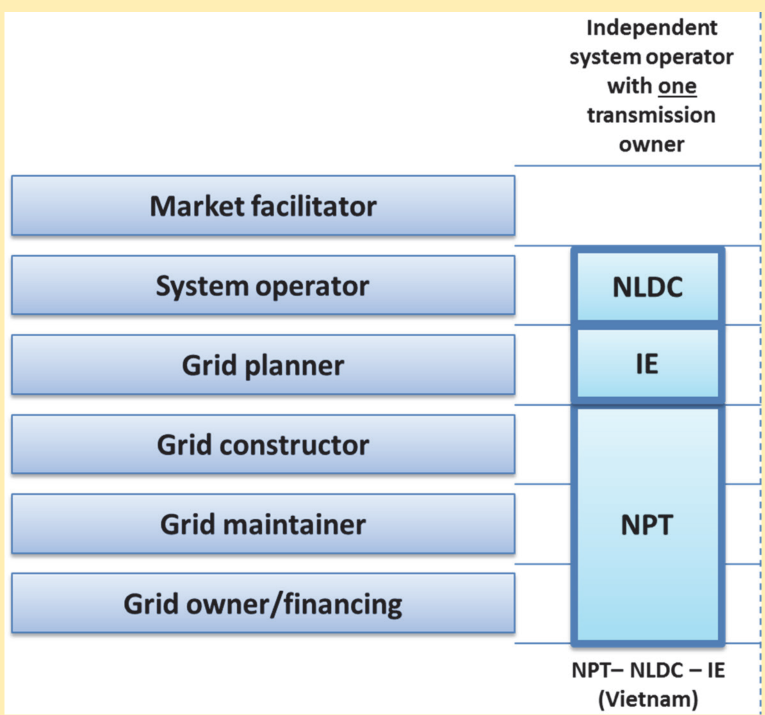
Thus the models shown in paragraph 'Annex 1b' could be mapped to the Vietnamese Transmission System as shown in Figure 76, with an independent system operator, represented by NLDC, the planning organization represented by IE and the single transmission owner, represented by NPT.

It is worth noting that the transmission utility of the Vietnamese organization is quite similar to the Italian model up to 2005, as depicted in Figure 73. However, a closer look shows that the Vietnamese model is a little more complex, as it involves three players as opposed to just the two in the Italian case.

The absence of vertical integration in this kind of structure is one of the reasons why the Italian transmission system evolved into a single full-service TSO, as discussed in paragraph 'D.2.1'. This does not imply or suggest that the Vietnamese transmission utility has to follow the Italian example, but it will be important to take into account the peculiarities of their organizational structure when addressing Smart Grid solutions.

It is worth emphasizing this issue because implementing Smart Grid initiatives often involves more than just the one function of a transmission utility and, as in the Vietnamese model, more than one player. This may lead to greater complexity in the development of projects.

FIGURE 76: VIETNAMESE TRANSMISSION SYSTEM ORGANIZATION



Source: Authors

In order to promote the successful development of the Smart Grid roadmap a careful specification of the tasks for each player and a definition of the policies dictating their shared interactions will be key to the ultimate success of the initiative.

b. Main Vietnamese issues and challenges

In order to choose the most suitable and effective Smart Grid initiative for Vietnam, it is fundamental to identify its critical transmission system needs, starting with an analysis of the issues and challenges.

During the discussions with NPT technicians several issues were highlighted, basically relating to on-going problems associated with the management and operation of existing assets. These problems were described in an earlier report and the most relevant ones are summarized in the following section.

b.i. Network topology issues

In May 2013 the southern region of Vietnam experienced a massive power outage. This was caused by a truck that, while delivering a tree, damaged a line in the national power grid (500 kV) in New Bình Du'o'ng City urban area. The transmission system was not compliant with the N-1 security criterion, so the truck incident led to a cascade effect causing a wide-ranging blackout across twenty two provinces. This is a typical case where a small incident has a major knock-on effect causing significant damage. This event also revealed that there was no insurance coverage for the assets of the electrical system to compensate for unexpected outage events and the associated damage.

In addition to this serious event, there have been other lower impact incidents that have occurred with some frequency on the network and reveal major topology weaknesses.

First of all the Vietnamese network structure reflects the geographical shape of the country, which is long and narrow. This has influenced the location of the generation sources most of which are concentrated in the North and in the South. Thus, Vietnam is characterized by a high North-South power flow, over the 500kV backbone links [30]. This imposes operational limitations and exposes the system to a high risk of instability, especially from the point of view of transient and voltage stability.

Furthermore, from the discussion with NPT technicians and the consequent analysis of the grid single line diagram, the current Vietnamese topology looks highly meshed. This structure leads to a very high fault current that exceeds the rated current of circuit breakers with consequent failures affecting their opening. This happens on the 220 kV network where most of the circuit breakers have a rated current of 40 kA.

The current section explores the problems of network topology (transient and voltage stability, short circuit level, etc.) while some solutions in terms of both the Transmission System Enhancement initiatives (paragraph 'E.3') and the Smart Grids projects (chapter 'F') have been proposed.

b.ii. 500kV limited transient stability

The first limitation caused by the present Vietnamese network topology regards transient stability. This primarily concerns the 500kV network, where even a single disturbance (such as the tripping of a 500kV circuit breaker) is likely to exceed the stability limit and cause the system to become unstable.

NLDC simulations have shown that instability can occur when the line is heavily loaded (1,200MW for a single line and 1,700MW for two parallel lines) and the instability risk is increased when the Da Nang, Pleiku 500kV substations operate with inadequate devices (i.e. lacking one or more circuit breakers) [30].

The system's transient stability margin significantly increases when most of the substations are operated with the 380/200 kV transformers connected, especially when the link is operating with two complete parallel circuits. With two parallel lines, the voltage and transient stability limits are both improved.

b.iii. Voltage Stability, Profile and Support/ Reactive Power Balance

The current network topology includes several shunt devices to manage and optimize the generation of reactive power on the various voltage level networks.

On the 500 kV network shunt reactors are installed for compensation of the transmission lines. On the 110 kV system, several shunt capacitor banks are present for the generation of reactive power and voltage support. These systems allow discrete reactive compensation, through switching capacitor banks in response to network conditions.

The use of circuit-breakers equipped with Point Of Wave (POW) systems (switch-sync relays) may allow a smoother operation of these compensation systems and the reduction of transient disturbances following a switching (opening or closing) event. Unfortunately, even with this POW feature it would not be possible to support a rapid and continuous adjustment of reactive power injection.

Therefore, one of the main side effects of using such discrete shunt compensation devices is the difficulty of ensuring reliable voltage regulation. This is particularly true for the long transmission lines and highly variable loading conditions, due to the unbalanced distribution of load and generation.

The analysis of the documentation on the Vietnamese grid has identified various operating conditions in which the voltage tends to fluctuate within a wide range of values.

Operating conditions are reported where the minimum threshold voltage of 0.9 p.u. is exceeded during peak hours, with heavily loaded 500 kV lines and, on other occasions, with a significant high voltage level during low load hours, public holidays or at night.

Both the above cases, i.e. relatively high or very low voltage levels, could cause non-optimal working conditions for the transmission network, with a significant increase in transmission losses resulting in both thermal and dielectric stresses of the system components.

Moreover, whenever the system operates at loads that are too close to the operational voltage limits the network operator is forced to change the configuration of the system, leaving the network in a critical condition with loss of redundancies and reduction of operating margins which in turn reduces the system's resilience to device or line failures.

The use of Static Var Compensator (SVC) devices and the appropriate tuning of the relevant control systems in particular combined with the introduction of power oscillation damping functions, will help to stabilize the network, while increasing the transmission capacity, optimizing the voltage profile and consequently also reducing losses along the lines. This topic is addressed in section 'F.7'.

In particular, a suitable reactive power infrastructure on the 500 kV transmission grids will help to maintain adequate voltage profiles and reduce the susceptibility of the system to the risk of voltage instabilities, which might occur in conditions of high load and particularly with reduced voltage at the receiving end of the system.

b.iv. Short Circuit Level

This issue mainly impacts on the substation equipment rating and the definition of the 500/220 kV step-down transformer characteristics (rated power, short circuit impedance, short circuit resilience, paralleling of the units).

The use of specific components, devices and provisions to limit the short circuit current are related to addressing particular needs and requirements.

NPT has already envisaged the possible use of a series reactor in combination with bus-bar sectionalization in order to contain the short circuit level within design limitations. This solution impacts the operational security of the system, in particular during peak load conditions and when faced with contingency/transient occurrences, since the system could then experience stability problems.

Only the execution of a detailed load flow and contingency analysis can verify if the proposed configuration is suitable for ensuring the limitation of the short-circuit current without impacting on the system's operation. This calculation also aims to determine the proper splitting points, ensuring the correct generation/load balance and the fulfillment of transmission capacity constraints for various sections of the system, all whilst ensuring the parallel operation of the system as a whole.

There are some smart technologies that can provide a better operational approach for this problem whilst ensuring a more resilient configuration of the system. In principle the use of the advanced assessment features of an EMS (see E.3.2 which looks at State Estimation and N-1 Security assessment) will allow the precise identification of operating conditions and constraints of the system and therefore allow the correct compartmentalization of the 500/220 kV network.

Moreover, the adoption of Special Protection Schemes (SPS) will also allow fast reconfiguration of the grid (e.g. contingency-based remedial action schemes and advanced remedial action schemes) after a potentially dangerous event.

b.v. Lightning Performance of exposed 220 kV lines

Some sections of double circuit lines located in the northern area of the NPT grid have problems due to the fact that the single-phase auto re-closure cycle fails owing to the presence of a secondary arc-current that precludes the extinction of the arc at the fault location.

A possible solution being considered by NPT is the installation of suitable Line Surge Arresters (LSAs) in order to increase performance of these lines in the presence of lightning. The technical literature shows several examples of the application of LSAs to increase the performance of the OHTLs, typically for lower voltages (60, 110, 132, 150 kV), but it has also been known to work for 220 kV and higher system voltage levels.

Positive results can be achieved providing that the selected solution is developed on the basis of a detailed technical analysis with the choice of the type (i.e. gap or gapless) and the location of LSAs made according to the configuration of the line as well as the correct identification of those towers with the highest probability of being struck by lightning (using suitable insulation coordination software tools). Additionally the analysis would also need to identify those areas most exposed to lightning with relevant Ground Flash Density figures and definitions of the type and value of the grounding parameters of the OHTL towers.

There are also some smart applications that can be leveraged to address this specific issue. In principle the implementation of a Lightning Monitoring and Detection system will allow the operator to identify the occurrence of hazardous conditions in advance, and then facilitate possible actions for system reconfiguration and power flow re-dispatching, in order to minimize the impact of an outage of a line adversely affected by a lightning strike.

b.vi. Defense Plan Improvements

The Vietnamese blackout in May 2013 revealed the weaknesses and/or failures in the current protocols for remedial actions in the event of unexpected massive outage.

The system was not fulfilling the N-1 Security criterion as neither the defense plan nor the protection scheme (if any) had been able to counteract the initial fault.

If the Vietnamese power system experiences an under frequency load shedding, its remedial actions would be completely inadequate to face transient instability of such severity. The reasons for the failover deficiencies during such significant events must be investigated. Likewise, if a generation shedding scheme is operating on the grid, the cause of its failover must be identified to address the most effective security enhancement.

Although, the grid topology and the other documented incidents happened before 2013, it does suggest that the most probable cause of the massive black out could have been a cascade line tripping due to transient instability of the 500 kV lines. Thus, the Vietnamese power system was lacking an appropriate special protection scheme rather than suffering from an inadequate under frequency load shedding scheme. If the system was not fulfilling the N-1 security criterion, a SPS remedial action should have been in place to guarantee a swift reaction to line tripping.

b.vii. Load-Frequency regulation Improvements

The Vietnam Primary Load-Frequency regulation description issues were discussed with NPT technicians during the discovery process.

Primary frequency regulation is crucial to maintain reliable operation of the system after an incident. The primary control center must maintain the frequency within the allowed range by increasing (or decreasing) the generated power, preventing the frequency drop (or raise). In case of limited contingencies, primary control must handle the imbalance caused by events without any underfrequency load shedding or generation tripping. Like other protection equipment, the primary control is the first line of defense of the network against disturbances. Like protection devices it relies only on local measurements (frequency at generator's terminal) and must react in a matter of seconds.

Presently this type of regulation is achieved by using a single hydro power plant at a time, chosen from a set of five possible hydro power plants depending on network conditions. Although no particular concerns about frequency stability has been highlighted by NPT technicians, some enhancements of the Primary Load-Frequency regulation should be considered in the near future.

b.viii. Miscoordination of Protection Systems

Given the current network topology and the need to maintain a complete "meshing" of the existing stations, any miscoordination or malfunction of protection systems can potentially lead to the loss of a large portion of the system with the attendant risk of general system instability and blackouts or brownouts. This can happen both in the case of intervention of back-up functions following the failure of the base protection function/device or in the case of a failure of the first-line protection functions.

Some examples of problems caused by the failure of primary components (e.g. circuit breakers) that led to these events were provided by NPT personnel. Various events have been identified in which the origin of the shutdown of part of the system is related to the malfunction or miscoordination of the protection system probably due to interference and electro-magnetic compatibility issues on secondary signals.

One of the on-going NPT development activities is actually relevant to the definition of basic specifications for protection and control systems to be installed in their new stations. However, it seems that the focus of this activity is essentially aimed at ensuring basic and common characteristics (i.e. interoperability) that will then allow the NPT to interface systems provided by different suppliers. The activity of defining these basic specifications should also include the definition of requirements to fully ensure compliance with electro-magnetic standards in order to overcome the reported problems of the EMC.

It is worth considering that the possible integration of smart technologies such as the adoption of systems and advanced IED minimizes the use of traditional copper cabling and maximizes the exchange of data/signals via fiber optics thus removing the risk of RFI disturbance and consequent operational failure. This would have the additional benefit of integrating easily into any proposed Smart Grid environment.

b.ix. SCADA & Remote Control Centers

Several new technologies are either in place or in the design approval phase within the EVN structure for the creation of a remote management system for the network. These initiatives range from the installation of RTU/Gateways in existing substations, required for the interfacing of local devices, the installation of communication networks/WANs and then SCADA/EMS plus SCADA for remote control centers (both for the PTC areas and central NPT remote control center).

General requests from NPT are related to the identification of criteria, principles and functionalities to be provided for the set-up of a remote control center. Prior to this, a proper coordination and supervision initiative is required to define a common strategy aimed at optimizing the specification and subsequent installation of these infrastructures, with a view to integrating with possible future requirements as well as meeting the present day needs of the users.

The definition of these basic structures for communication and system control is fundamental to creating the right enabling platform for a transition towards smart grid applications and functionality.

b.x. Time and cost reduction of asset maintenance

As stated in paragraph 'Annex 2a' above, Asset Management is one of the main responsibilities of the NPT and one of their most critical concerns is the time and cost of asset maintenance.

In particular after a fault, the time and costs necessary for all the physical interventions, in the first instance, depend on the time taken by field technicians to locate the fault. There are different types of initiatives that could be put in place to address this requirement. The number of faults can be significantly decreased by improving Asset Management and Planning strategies and reducing the risk of the protection systems miscoordination or malfunctioning in the first place.

It is possible to implement Smart Grid solutions aimed at reducing the time and cost of asset maintenance. Towards this end NPT has begun to implement a Fault Locator System (FLS) that, thanks to its high precision in fault localization, can improve the efficiency of intervention for damaged components and thus significantly improve the mean time to repair.

b.xi. Power Quality

In the Grid Code, the power quality reference levels and applicable limits are clearly defined for the transmission network (in particular harmonic distortion and flicker). In reality, at the moment there is no monitoring of power quality on the Vietnamese network and nor does there appear to be any plan for incorporating monitoring capabilities in the near future. Even the most basic analysis of availability levels guaranteed for the transmission system appears not to have been done in a systematic way.

The creation of an infrastructure for monitoring the level of power quality could be a starting/enabling element for identifying and monitoring the level of functionality of the data network and the implementation of future applications that guarantee the fulfillment of quality levels that are likely to be required by new markets (e.g. sensitive industrial loads and RES).

b.xii. Interconnections with Cambodia, China and Laos

The 220 kV interconnection with Cambodia was initially installed and operated purely as a means of selling energy to a load center.

The current interconnection set-up is not experiencing any operational problems and at present a telephone link is used between the operators of the two systems to send instructions and exchange information.

The future development of the system and the possible introduction of hydro generation on the Cambodian side (and a similar arrangement is expected with Laos in the near future) will require very different operating conditions. In particular, it will be necessary to define adequate operational procedures and a more efficient interface between the operators of the provider and client systems.

In order to address these issues it is proposed that advanced applications and management systems be introduced to assist the operators of the two systems.

Part of the northern Vietnamese electrical network is connected to the Chinese grid through 110 kV and 220 kV over-head-lines, importing around 5 TWh/year. However, at the time of writing this report this link cannot be considered an interconnection between the two countries since this part of the Vietnamese network is separated from the rest of the national system when it is connected to China.

In the near future the situation could change seeing that there are projects under evaluation for building new 500 kV lines permanently interconnecting the two countries. In this case advanced applications and other management systems to assist the operators of the two systems are necessary.

Annex 3. FACTS Technology

FACTS technology was originally developed to support systems with long AC transmission lines but FACTS installations are nowadays more often used in meshed grids to eliminate congestion and bottlenecks.

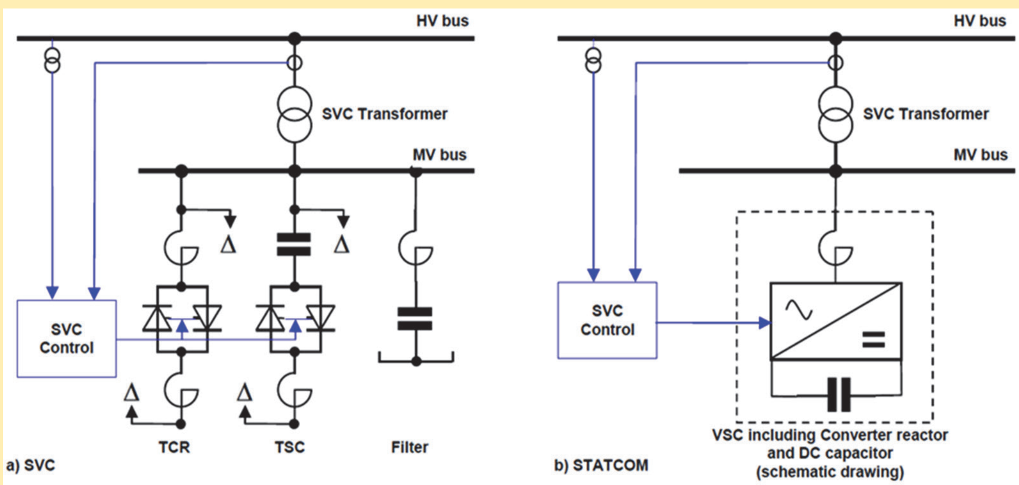
Depending on the type and rating of the selected device and on the specific voltage level and local network conditions, the transmission capacity enhancement achievable by installing a FACTS element could be as high as 40-50% [31].

In comparison with traditional mechanical devices, FACTS controllers, by virtue of having no moving parts, experience no wear and tear and thus require much less maintenance.

In general, FACTS devices can be traditionally classified according to the manner in which they are connected [32], that is as:

a. Shunt controllers. Among shunt controllers the main devices are the Static VAR Compensator (SVC) and the Static Synchronous Compensator (STATCOM). Typical schematics for these systems are provided in Figure 77.

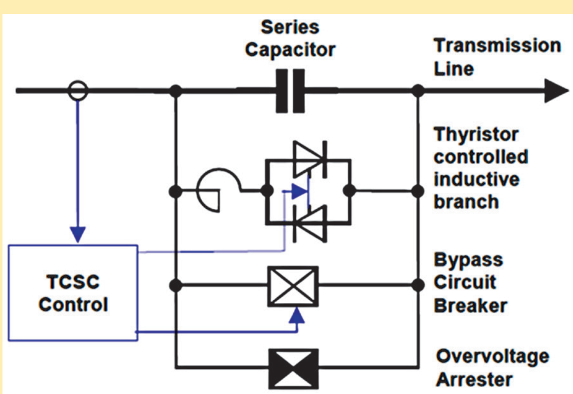
FIGURE 77: SVC AND STATCOM CONFIGURATION



Source: Friends Of the SuperGrid, 2012, (21)

b. Series controllers. The series controller category includes devices such as the Thyristor Controlled Series Capacitor (TCSC) and a typical schematic for this system is shown in Figure 78.

FIGURE 78: TCSC CONFIGURATION



Source: Friends Of the SuperGrid, 2012, (21)

Combined controllers. The combination of Series and Shunt Compensators systems typically used to further increase the manageability of AC transmission systems are known as Unified Power Flow Controller (UPFC).

FACTS devices can also be classified according to the power electronics technology used for the converters, as follows:

a. Thyristor-based controllers. This category includes those devices based on thyristors, namely the SVC and the TCSC;

b. Voltage source-based controllers. These devices are based on more advanced technology like Gate Turn-Off (GTO) thyristors, Integrated Gate Commutated Thyristors (IGCT) and Insulated Gate Bipolar Transistors (IGBT). This group includes the STATCOM;

c. The voltage source-based devices are the most advanced FACTS systems and offer a smoother and faster control of active and/or reactive power flow and/or nodal voltage amplitude independently of the loading/current conditions.

A general identification of the different types of FACTS developed for applications within a transmission network is given in the table of Figure 79.

FIGURE 79: FACTS DEVICES

Thyristor based FACTS	Thyristor Controlled Series Compensator (TCSC)	Controls Z
	Static Var Compensator (SVC)	Controls V
	Thyristor Controlled Series Compensator (TCSC)	Controls Ø
Transistor based FACTS	Static Synchronous Compensator (STATCOM)	Controls V
	Unified Power Flow Controller (UPFC)	Controls V, Z, ø and P
	Convertible Series Compensator (CSC)	
	Inter-phase Power Flow Controller (IPFC)	
	Static Synchronous Series Controller (SSSC)	
Energy Storage + FACTS	Super Conducting Magnetic Energy Storage (SMES)	Controls V and P Emergency Power & Black Start
	Na-S or Li-ion Batteries Storage	

Source: Authors

Considering the state of development and the real application examples available today, the notes below refer only to the most commonly used major systems such as SVC, TCSC and STATCOM.

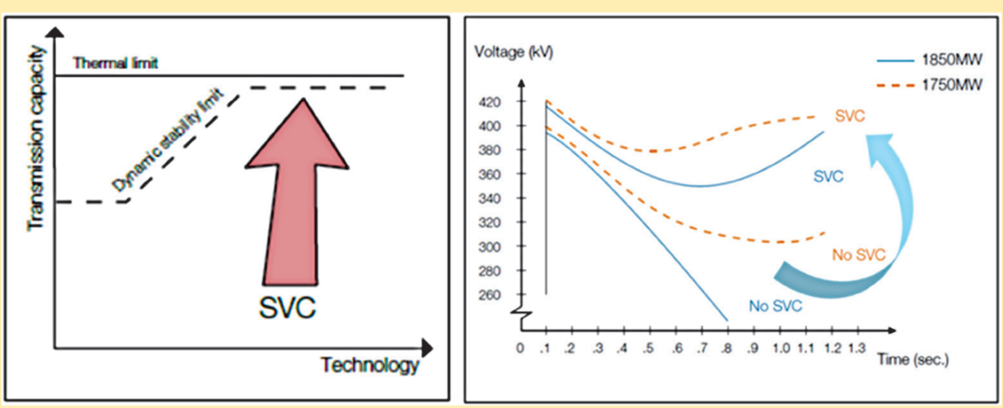
The development of the VSC converter has led to the development of VSC HVDC applications embedded in AC systems, as discussed in detail in the previous section 'D.4.4', instead of the use of UPFC or similar systems. This is because a cost/benefit analysis usually favors the adoption of a HVDC systems rather than the implementation of a complex FACTS system.

Nevertheless, the exploitation of the main features and capabilities of the aforementioned basic FACTS devices such as SVC, TCSC, STATCOM, is wide spread as they have been in service in transmission networks for several decades especially to address network congestion instead of the traditional solution of increasing the transmission capacity by building new lines and substations [33].

In this sense, FACTS are an effective way to optimize the existing transmission structures and to free paths that are occupied by undesired power flows (i.e. active loop flows, reactive power flow) in order to make better use of the existing lines, up to the maximum possible operating conditions thus reducing losses and preventing possible system congestion.

Figure 80 outlines the expected typical impact of a SVC system in terms of increasing the transmission capacity and stabilization of the system voltage.

FIGURE 80: ENHANCEMENT OF THE SYSTEM STABILITY BY MEANS OF A SVC



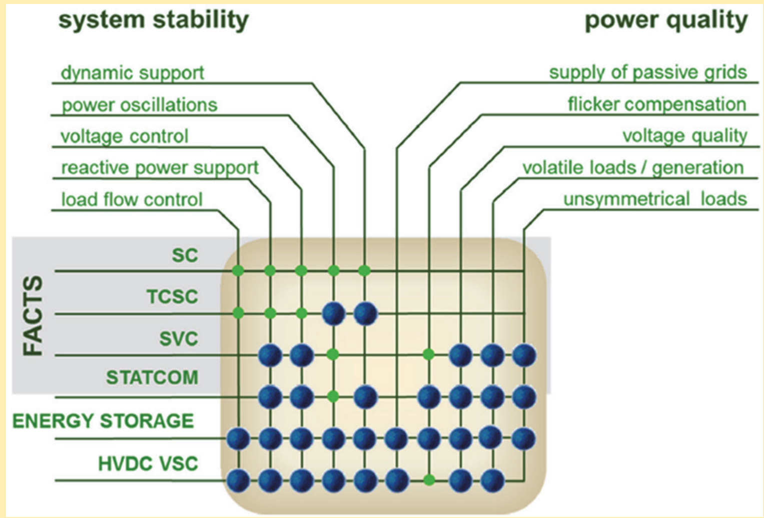
Source: ABB, 2013, (8)

Figure 81 shows a more general view of the variety of possible applications for the range of FACTS devices relative to the various problems that might be experienced in a transmission network.

The matrix shows a broader picture of the possible application of power electronic devices and includes issues with power quality in distribution networks and for consumers where FACTS devices have been successfully deployed as well as for HVDC applications as discussed in section 'F.8'.

Typical examples of possible applications are increasing the transmission capacity within a section of the existing power grid or setting-up a new connection to the main grid for large remote generation units and include new interconnections with TSOs of neighboring countries.

FIGURE 81: FACTS APPLICATIONS FOR POWER QUALITY AND SYSTEM STABILITY



Source: IEA, 2013, (20)

In this case an advanced solution, based on the introduction of FACTS applications, is often favored over conventional alternatives.

This approach always requires a detailed analysis to consider all the possible aspects and it is necessary to set-up suitable technological, economic and environmental criteria to be applied in order to verify that the FACTS solution is the best of all possible options examined during the transmission expansion planning process.

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ENDNOTES

1. Operational Expenses
2. Energy Not Served
3. Phase Measurement Units
4. Internal Rate of Return

2

Volume 2: Cost-Benefit Analysis

Table of Contents

A. Acronym List

CAPEX	Capital Expenditures
CBA	Cost Benefit Analysis
DGA	Dissolved Gas-in-oil Analysis
DLR	Dynamic Line Rating
DTCR	Dynamic Thermal Circuit Rating
ENS	Energy Not Served
ERAV	Electricity Regulatory Authority of Vietnam
EVN	Electricity of Viet Nam
FLS	Fault Locator System
GHG	Green House Gas
GIS	Geographic Information System
HVDC	High Voltage Direct Current
IED	Intelligent Electronic Device
JRC	Joint Research Centre
KPI	Key Performance Indicator
LLS	Lightning Location System
LNG	Liquefied Natural Gas
LSA	Line Surge Arrester
MBTU	M (a thousand) British Thermal Unit
NARUC	National Association of Regulatory Utility Commissioners
NLDC	National Load Dispatch Centre
NPT	National Power Transmission Corporation
NPV	Net Present Value
OPEX	Operating Expenditures
PMU	Phase Measurement Unit
PQ	Power Quality
SAS	Substation Automation System
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SVC	Static Var Compensator
VoLL	Value of Lost Load
WAMS	Wide Area Monitoring System

B. Summary of Cost-Benefit Analysis

This document presents Cost Benefit Analyses of Smart Grid Applications. The Project started by designing the strategy and gathering information in order to perform an adjusted Roadmap of a Smart Grid implementation for Vietnam. The first step in the project was to identify the possible Smart Grid Applications and Smart Grid devices that may help to resolve the problems identified by the Vietnamese power authorities. The Task-1 report defined a common shared vision of applications and equipment for the Smart Grid development in Vietnam starting with the current operating model and the predicted status of the electricity sector.

The Smart Grid initiatives were tailored to fit the specific needs of Vietnam, taking account of not only the best international practices and experiences but also the current operational problems and the current status of the Smart Grid initiative in Vietnam.

The technical analysis performed in Task-1 identified the Smart Grid initiatives that are viable in Vietnam. These solutions have been provisionally prioritized after a technology-focused investigation.

The Cost-Benefit analyses performed in this report aim to identify the costs and benefits of each proposed Smart Grid initiative and evaluate their economic parameters in order to understand the real added value of each initiative.

In order to have a complete understanding of the proposed Smart Grid initiatives from both the technical and economic points of view, it is fundamental to perform a Cost-Benefits Analysis (CBA).

In order define a starting point for this analysis it is crucial to understand the baseline scenario and the predicted growth rate of the Vietnamese transmission system. Towards this end some base assumptions have been made and shared with the Vietnamese stakeholders. These are and summarized in Table 17.

It is essential to identify the costs of each Smart Grid solution and to evaluate their economic and technical benefits in order to understand the real added value of each initiative.

Starting from some basic assumptions regarding the type of benefits (direct and system level), costs (Capital Expenditures—CAPEX—and Operating Expenditures—OPEX)

TABLE 17: SMART GRIDS BUSINESS CASE—SUMMARY OF BASE ASSUMPTIONS

Topic	Major assumptions
Peak demand	• Baseline data (2015) in GW = 22.5 (source: NLDC). • The predicted average peak load growth rate over a 15 year timeframe is +9%/year (source: NLDC).
Consumption	• Baseline data (2015) in TWh = 161 (source: NLDC). • Predicted growth rate over a 15 year timeframe is 7-8%/year (source: NLDC).
Number of customers	• Baseline data (2012) equal to 19.781 million, with 18.564 million residential customers, 391,493 commercial customers, 53,296 Agricultural and 518,610 industrial customers and 253,919 others. • Predicted growth rate over a 15 year timeframe is 8%
Power capacity	• Baseline data (2015) of installed capacity in GW = 33 GW (source: NPT). • 2030 installed capacity = 146.8 GW (source: NPT) of which: o Hydropower accounts for 11.8%; o Energy storage hydropower for 3.9%; o Coal thermal power for 51.6%; o Gas fired power for 11.8% (of which LNG 4.1%); o Power using renewable energy for 9.4%; o Nuclear power for 6.6%; o Imported power for 4.9%.

(Continued next page)

TABLE 17 (CONTINUED)

Topic	Major assumptions
Transmission network sizing	• Transmission lines (source: NPT-NLDC): o 500kV = 6,756 km (2014), ~+16%/year growth rate (average in period 2009 – 2014) o 220kV = 12,513 km (2014), ~+6.6%/year growth rate (average in period 2009 – 2014) • Transmission substations: o 164 (2015), ~+7% new substations/year • Transformers (source: NPT-NLDC): o 500kV = 21,900 MVA (2014), ~ +32% per year (average in period 2009 – 2014) o 220kV = 31,351 MVA (2014), ~+15% per year (average in period 2009 – 2014)
Transmission network performances	• SAIFI: 27.975 in 2013 (source: EVN estimation); • SAIDI: 4,461 minutes in 2013 (source: EVN estimation); • Network losses equal to 2.49%, whose technical assumed 70% and non-technical 30% (source: NPT); • The total cost for system operation is $400,000,000 per year (source: NPT, 2014).

Source: Authors

the CBA evaluates the Key Performances Indicators (KPIs) of each Smart Grid application in the context of the Vietnamese transmission system. In particular, the CBA is based on the steps recommended by the Joint Research Centre Institute for Energy and Transport (JRC). Based on the mapping of initiatives onto functionalities and of functionalities onto benefits for each Smart Grid solution it has been possible to quantify these direct benefits:

a. Direct Transmission OPEX reduction;

b. Reduction of energy not served;

c. Reduction of power losses;

d. Improved system reliability through reduced frequency and duration of system faults;

e. Amount of CAPEX investment in transmission system saved;

f. Deferred investment in Capacity enhancements.

In order to express these benefits in financial terms some assumptions have been made for each Smart Grid initiative. The most challenging ones are related to "Direct Transmission OPEX reduction" and to "expected Energy Not Served (ENS) reduction" due to a fault event prevented or avoided.

The savings that can be achieved through optimization of operating costs by using automation are assumed to range between -5% and -10% based on international experiences (e.g. the Italian case). Such benefits can, of course, vary significantly as a function of specific network characteristics and architecture, productivity of resources involved in network operations and the levels of regular maintenance and service provided. The literature on this issue is quite limited and a detailed study would be necessary to obtain the exact value of the likely Direct Transmission OPEX reduction for Vietnam. However, exhaustive analysis of this aspect is outside the scope of this work, a conservative estimation of the financial value of the benefits has been made for the purposes of performing the CBA. The operating cost reduction potentially achievable from a Smart Grid development has been assumed to be 8%. This is based on the consultant's extensive experience in this field garnered from similar international projects, and takes account of the current status of the variables likely to affect this estimation that are present in the Vietnamese scenario. The individual Smart Grid initiatives contribute in different ways to achieving this level of cost reduction.

In order to estimate the amount of ENS reduction for some of the initiatives it has been assumed that a certain type of fault event on the transmission network (e.g. a voltage collapse) causes a brownout each year corresponding to a certain percentage of the peak load (e.g. 10%) and such an event lasts for a number of minutes (e.g. 30 minutes). A review of the available literature on the subject has failed to shed any light on the link between the cost savings from a Smart Grid based ENS reduction and the commensurate level of OPEX reduction. Therefore, once again, the cost benefit analyses presented in this document relies on the consultant's experience of the knock on benefits of ENS reductions and offers a conservative estimate that, again, takes account of the prevailing situation discovered within the context of the Vietnamese power network.

The major assumptions regarding the direct benefits offered by the Smart Grid applications are summarized in Table 18.

TABLE 18: SUMMARY OF BENEFITS MONETIZATION ASSUMPTIONS ON SMART GRID INITIATIVES

Initiative	Major assumptions regarding benefits
SAS	• A SAS installation can contribute about 60% to the global reduction of the OPEX for the transmission system. • An average value of ENS reduction per year, per substation equipped with SAS is about 100 MWh. • The cost of ENS is 3,000 $/MWh.
WAMS	• A WAMS installation can contribute about 10% to the global reduction of the OPEX for the transmission system. • The total number of voltage collapse events cause approximately 10% of brownouts of the peak load per year accounting for a total of 30 minutes. • The prevention capacity is directly proportional to the pace of installation. • All new substations brought on-line and 68 of the old ones will be equipped with PMUs. • WAMS functions that help prevent such events will be available after 3 years from the start of the project. • The brownout prevention capacity is increased by 20% if all substations are equipped with PMUs.
Lightning Location System	• A Lightning Location System can contribute about 5% to the global reduction of the OPEX for the transmission system. • The phase-to-phase-to-ground faults caused by lightning account for 8% of the total number of faults caused by lightning. • These events cause about 2% brownout of the peak load per year accounting for a total of 30 minutes. • This application will result in a 25% reduction of the number of phase-to-phase-to-ground faults caused by lightning. • The ability to prevent such events will be available 3 years after the start of the project.
SVC	• SVC installation can contribute 10% to the global reduction of the OPEX for the transmission system. • The total number of voltage collapse events cause approximately10% of brownouts of the peak load per year accounting for a total of 30 minutes. • This application will result in a 25% reduction of the number of voltage collapse events.
HVDC	• A HVDC link can contribute 5% to the global reduction of the OPEX for the transmission system.. • 500 kV and 2000 MW rated power for both AC and HVDC solution. • AC and HVDC lines are the same length. • The OPEX is calculated at 1.5% of the capital expenditure for both AC and HVDC lines. OPEX for converter stations is 3% of their CAPEX (source: manufacturers). • Annual energy losses are calculated according to the following formula: o L_year=8760 LF X L_Pmax; where: o LF = 70% is the loss factor, corresponding to 6,132 equivalent hours; and o L_Pmax are the losses at rated power and depend on the type of the transmission (AC or HVDC) and the size of the conductors. • The financial value of energy losses is estimated to be 60 $/MWh per year. • The annual financial value of the reduction of power losses is based on the difference between the value of AC and HVDC energy losses per year.
FLS	• These events account for about 10% brownout of the peak load per year amounting to a total of 30 minutes. • The prevention capacity is directly proportional to the number of lines equipped with FLS devices. • This application will result in a 25% reduction of time lost because of faults.
DGA	• Average cost of a transformer fault is approximately $9,000 per MVA and the fault probability is estimated to be about 0.6%. • The installation of this device in transformers will prevent about 80% of faults.
Dynamic Thermal Circuit Rating	• Dynamic Thermal Circuit Rating can contribute 5% to the global reduction of the OPEX for the transmission system. • It is proposed that four critical lines be equipped with DLR sensors. • These lines are 100km in length. • The costs estimated for these four lines include the cost of the DLR solution (1 sensor every 10km) and of reconductoring. • A DLR sensor costs $32,000 while the reconductoring costs $200,000/km.
GIS	• It is assumed that the GIS application will only be developed for the SAS initiative and it is expected to result in a 10% reduction in the OPEX for the SAS project.
Power quality monitoring and Metering Data Acquisition Systems	• Power quality monitoring and Metering Data Acquisition Systems can contribute 5% to the global reduction of the OPEX for the transmission system.. • The fault events caused by critical voltage dips account for about 1% brownout of the peak load per year amounting to a total of 15 minutes. • The prevention capacity is directly proportional to the number of lines equipped with PQ devices. • Power Quality monitoring will result in a reduction of 20% of fault time losses.

Source: Authors

The analyses performed also consider the cumulative benefits at a system level of multiple smart grid initiatives. The assessment and the financial benefits of each Smart Grid application has been performed independently and not compounded in the calculation of the economic indicators at a system level, thus deliberately underestimating their overall benefit.

In order to be conservative and not overstate the case for the Smart Grid applications, the cumulative financial value of the system level benefits has not been included in the economic evaluation of each Smart Grid initiative. However, the estimated financial value of each application has been compounded to create an economic indicator for the Smart Grid roadmap in its entirety. Such an incremental global evaluation highlights how the development of even a subset of Smart Grid solutions (as required for Vietnam) will expedite the construction of a "Smart" transmission network to enhance the reliability of the electrical system.

The support for the integration of renewable energy generation enabled by a Smart grid development has also been analyzed. International experience, in fact, demonstrates that Smart Grid solutions can facilitate the integration of Renewable Energy Sources whilst limiting the need for any additional infrastructure and improving overall system operation. The contributions of the individual Smart Grid initiatives are described with an emphasis on HVDC technology and Dynamic Thermal Circuit Rating both of which are particularly useful for integrating variable renewable energy generation sources.

The benefits of blackout prevention, entirely achievable with the deployment of Smart Grids, are also investigated. International experience of the highly damaging effects and high costs associated with blackouts were the main drivers behind the development of Smart Grids technologies in the USA, Europe and around the world. The benefits derived from blackout prevention are considered for the Vietnamese context.

Further, a cost estimation has also been performed to provide a complete understanding of the key economic parameters associated with the proposed Smart Grid solutions. The costs have been broken down in terms of capital expenditure for the design activities, systems and installation (CAPEX) and the operating expenditures of running, managing and administering the installed system (OPEX). The nominal and discounted values of such costs have been amortized over a period of15 year and are summarized in Table 19.

TABLE 19: SUMMARY OF COSTS OF SMART GRID INITIATIVES

Initiative	Nominal Costs	Discounted Costs	Scale of operation
SAS	• CAPEX: $226,200,000 • OPEX: $25,205,250	• CAPEX: $147,903,537 • OPEX: $10,854,340	• 18 retrofitted substations. • 150 new SAS.
WAMS	• CAPEX: $1,792,000 • OPEX: $214,840	• CAPEX: $1,268,311 • OPEX: $96,615	• 224 PMU installed at 500 kV and 220 kV voltage level.
Lightning Location System	• CAPEX: $1,668,000 • OPEX: $899,000	• CAPEX: $1,431,404 • OPEX: $443,395	• 20 detectors monitoring lightning activity across the country.
SVC	• CAPEX: $31,500,000 • OPEX: $1,255,500	• CAPEX: $24,962,690 • OPEX: $588,058	• 900 Mvar SVCs installed in the most affected areas of Vietnam.
HVDC	• CAPEX: ($16,800,000) • OPEX: $118,098,000	• CAPEX: ($13,313,434) • OPEX: $55,315,436	• 2,000 MW interconnection, 800 km length, using DC instead of AC technology.
FLS	• CAPEX: $8,400,000 • OPEX: Negligible	• CAPEX: $7,289,256 • OPEX: Negligible	• 140 Fault locators.
DGA	• CAPEX: $77,592,000 • OPEX: $3,343,245	• CAPEX: $41,696,690 • OPEX: $1,364,572	• 732 transformers equipped, (includes current and new).
Dynamic Thermal Circuit Rating	• CAPEX: $1,280,000 • OPEX: $371 200	• CAPEX: $1,110,743 • OPEX: $183,079	• 40 sensors monitoring 400 km lines.
GIS	• CAPEX: $175,000 • OPEX: $262,500	• CAPEX: $159,090 • OPEX: $133,106	• Geographic information of power system components throughout Vietnam.
Power quality monitoring and Metering Data Acquisition Systems	• CAPEX: $301,500 • OPEX: $97,214	• CAPEX: $241,648 • OPEX: $45,962	• 105 power quality measurement devices at 500 kV and 220 kV voltage level.

Source: Authors

It is worth noting that in all but two cases the cost evaluation considers the full investment in a project. The exceptions are LLS and HVDC where the calculation formula was slightly different.

The cost calculation variation for the LLS installation is because it is intertwined with the installation of the Transmission Surge Line Arresters (TLSA). The cost of buying and installing TLSAs has not been factored into this analysis because it has been assumed that the NPT has to install these devices independently of the installation of a Lightning Location System. Consequently for the LLS benefit evaluation in term of "**Reduction of energy not served**", the incremental fault reduction achievable with a TLSA installation driven by a LLS is considered.

Table 19 shows that CAPEX for HVDC is negative because an incremental cost benefit-analysis has been performed in this particular case. It is not possible to do a full cost benefit analysis because the benefit derived from the installation of a new line is something to be determined on a case-by-case basis and cannot be generalized. But since the benefit of the new line, in terms of optimization of energy mix, is independent from the technology used (AC or DC), an incremental cost benefit analysis is really useful to understand the impact of the adoption of a DC line instead of an AC one. This also highlights the further benefits that derive from using DC technology instead of the traditional AC. In either case it is possible to give the total CAPEX of the HVAC in comparison with the alternative HVDC interconnection. In the calculation performed for an over-head line of 800 kilometers (2 GW) the estimated costs are:

a. HVAC: $692,800,000;
b. HVDC: $676,000,000.

This means that the HVDC link offers a CAPEX saving of $16,800,000 or 2.42% of the cost of the HVAC link.

Therefore, the construction of a new HVDC line is not a smart initiative itself, but the real smart aspect is the choice of the HVDC technology for building already planned lines with certain characteristics instead of traditional AC technology.

In order to evaluate the economic benefits of each Smart Grid initiative four parameters have been chosen. These synthetic values are :

a. **Total NPV**: the Net Present Value represents the discounted cash flows, i.e. the present value of future cash flows calculated up to the year 2030;
b. **EIRR**: the Economic Internal Rate of Return on an investment or project is the "annualized effective compounded return rate" (or rate of return) that makes the Net Present Value of all cash flows (both positive and negative) of a particular investment equal to zero;
c. **B/C ratio**: the Benefits-Costs ratio summarizes the overall value for money of a project and it is calculated as the ratio of the discounted present values of benefits and the discounted present values of costs;
d. **Switching value**: This is the value assumed of an estimated benefit so as to equal zero NPV. The assumption is chosen specifically for each Smart Grid initiative considering both the uncertainty of its estimation and the impact on the economic benefits of the project. It is important to underline that the Transmission OPEX reduction benefit, if present, is considered equal to zero in the break-even calculation (conservative approach).

Table 20 summarizes the synthetic values of the economic benefits of each Smart Grid initiative.

It cannot be stressed enough that these values and indicators are very conservative, given the assumptions made and most importantly, given that the system level benefits discounted to 2015 derived from the optimized energy mix and increased fuel availability ($305,000,000), reduced GHG emission ($128,000,000) as well as the benefits accrued from major blackout prevention ($275,000,000) were not internalized in the economic indicators (NPV, EIRR and B/C ration). Thus, despite this deliberate underestimation, the indicators make a compelling and unambiguous case for the financial and technical benefits of Smart Grid technology in general and of these specific applications in particular.

Following the cost benefit analysis a sensitivity analysis was also performed. The purpose was to measure the impact of the changes to the project variables of the baseline scenario.

The variables assumed for the assessment vary for each specific application. For this reason each Smart Grid initiative has been separately analyzed in order to find the variables that are characterized by a high degree of uncertainty and yet have a significant impact on the economic evaluation.

Table 21 summarizes the sensitivity analysis parameters of each Smart Grid initiative.

TABLE 20: SUMMARY OF THE SYNTHETIC VALUES OF THE ECONOMIC BENEFITS OF SMART GRID INITIATIVES

Initiative	Results
SAS	• Total NPV: $179,002,262 • EIRR: 41% • B/C ratio: 2.13 • Switching value: Avoided ENS per SAS = 75.9 MWh/year (assumes Transmission OPEX reduction benefit equal to zero)
WAMS	• Total NPV: $22,951,362 • EIRR: 204% • B/C ratio: 17.82 • Switching value: Percentage of events prevented = 4.94% (assumes Transmission OPEX reduction benefit equal to zero)
Lightning Location System	• Total NPV: $11,035,144 • EIRR: 164% • B/C ratio: 6.89 • Switching value: Percentage of events prevented = 21.3% (assumes Transmission OPEX reduction benefit equal to zero)
SVC	• Total NPV: $5,265,412 • EIRR: 14% • B/C ratio: 1.21 • Switching value: Percentage of events prevented = 60.3% (assumes Transmission OPEX reduction benefit equal to zero)
HVDC	• Total NPV: $23,524,111 • EIRR: All positive cash flows[a] • B/C ratio: 1.56 • Switching value: Line length = 773 km (assumes Transmission OPEX reduction benefit equal to zero)
FLS	• Total NPV: $1,235,045 • EIRR: 13% • B/C ratio: 1.17 • Switching value: % monitored lines with faults = 64.1%
DGA	• Total NPV: $5,532,566 • EIRR: 12% • B/C ratio: 1.13 • Switching value: Average cost of a transformer fault = $7907
Dynamic Thermal Circuit Rating	• Total NPV: $44,132,102 • EIRR: All positive cash flows • B/C ratio: 35.11 • Switching value: Line reconductoring investment deferment = 0.18 years (assumes Transmission OPEX reduction benefit equal to zero)
GIS	• Total NPV: $762,214 • EIRR: 48% • B/C ratio: 3.61 • Switching value: % reduction of SAS O&M = 2.7%
Power quality monitoring and Metering Data Acquisition Systems	• Total NPV: $11,003,193 • EIRR: 797% • B/C ratio: 39.26 • Switching value: Percentage of events prevented = 10.0% (assumes Transmission OPEX reduction benefit equal to zero)

Source: Authors

Note: a. If the costs are already greater than the benefits in the first few years all the cash flows are positive and there is not a discount rate value, which determines a zero NPV.

TABLE 21: SUMMARY OF THE SENSITIVITY ANALYSIS PARAMETERS OF SMART GRID INITIATIVES

Initiative	Sensitivity analysis parameters
SAS	• Energy Not Served value. • Average value of ENS reduction per year for every substation equipped with SAS
WAMS	• Energy Not Served value. • Percentage of fault events prevented.
Lightning Location System	• Energy Not Served value. • Percentage of fault events prevented.
SVC	• Energy Not Served value. • Percentage of fault events prevented.
HVDC	• Power losses cost. • Line length.
FLS	• Energy Not Served value. • Reduction of Outage time duration. • Percentage of lines with faults monitored with the FLS.
DGA	• Average cost of a transformer fault.
Dynamic Thermal Circuit Rating	• Number of lines with deferred reconductoring. • Number of years of deferred investment.
GIS	• Operation and maintenance cost savings for SAS application.
Power quality monitoring and Metering Data Acquisition Systems	• Energy Not Served value. • Percentage of fault events prevented.

Source: Authors

A risk analysis was performed in order to gather all the key information for the final prioritization of the initiatives and the refinement of the Smart Grid roadmap.

The parameters used to evaluate the risks are as follows:

a. Risk categories;

b. Risk impact; and

c. Risk likelihood.

Based on these parameters a risk assessment was carried out for all the Smart Grid initiatives by weighing the risk impact with its likelihood and thus measuring the overall threat imposed by implementing each solution.

This comparison is graphically depicted on a two dimensional grid in Figure 82. The highest risk for each Smart Grid initiative is positioned on a map where the abscissa (x axis) represents the risk impact while the ordinate (y axis) represents the risk likelihood. The color shading across the 2D grid shows the relative risk whilst the color of each Smart Grid application identifies the risks in terms of three categories:

a. Green shows the "**Time**" category risk;

b. Violet the "**Stakeholders' actions**" category risk;

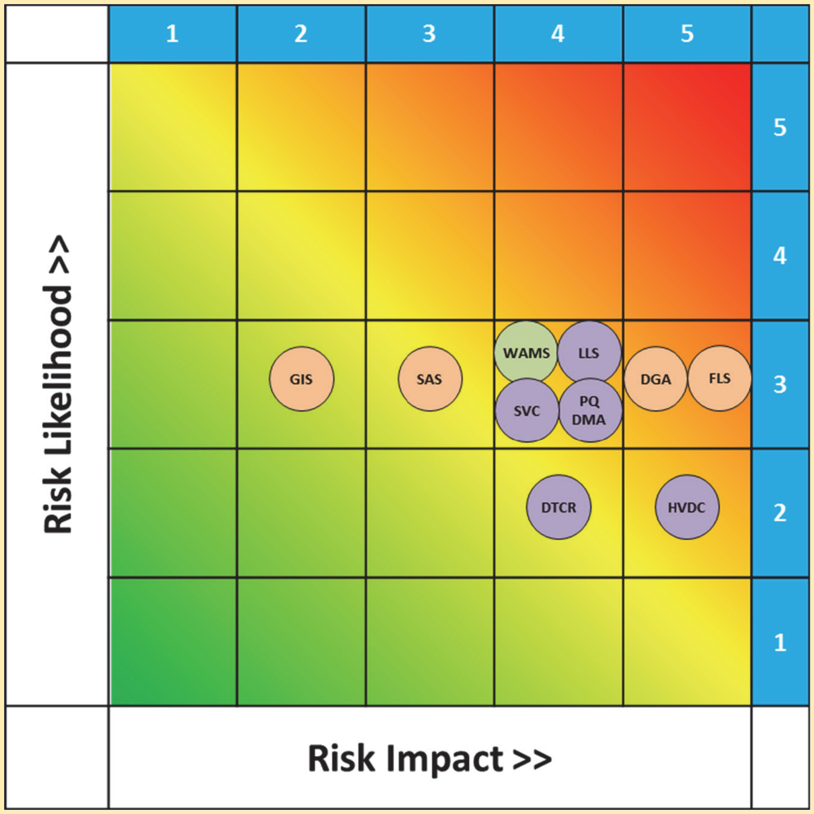
c. Orange the "**Investment uncertainty**" category risk.

This analysis has highlighted the solutions that carry the greatest risk such as FLS and DGA for want of "**Time**", "**Stakeholders' actions**" or "**Investment uncertainty**".

These risks cannot be fully eliminated but they can be mitigated by taking some appropriate actions.

However, despite these attendant risks the final prioritization of all the Smart Grid initiatives places them on a timeline, defines the best starting point for each and an ideal elapsed time for their development.

FIGURE 82: RISK MAP



Source: Authors

This prioritization is a refinement of the original Vietnamese Smart Grid roadmap and articulates a phased implementation plan. This prioritization is based on:

a. The technical reasons described in technical analysis report;

b. The economic results of the Cost-Benefit Analysis; and

c. The risks and related mitigating actions.

As stated in the technical analysis report, three different time horizons are considered for the development of the initiatives:

a. Short term—within the next 5 years;

b. Medium term—within the next 10 years; and

c. Long term—within the next 15 years.

The refined Smart Grid prioritization roadmap is as follows:

a. Geographic Information Systems positioned in the short term;

b. Dynamic Thermal Circuit Rating positioned in the short term;

c. Lightning Location System positioned in the short term;

d. Fault Locator System with recommended preliminary activities and their final completion in the short term;

e. Static Var Compensator with some preliminary activities in the short term with the finalization of the total installed capacity impinging on the beginning of the medium term;

f. Wide Area Monitoring System starts in the short term with completion occurring in the medium term. The prioritization of the main lines to all areas are in the short term;

g. Substation Automation System, including remote control centers building/upgrading, already started and therefore in the short term by default will be completed in the medium term;

h. Power quality monitoring system and Metering Data Acquisition System both start in the short term with the full rollout in the medium term;

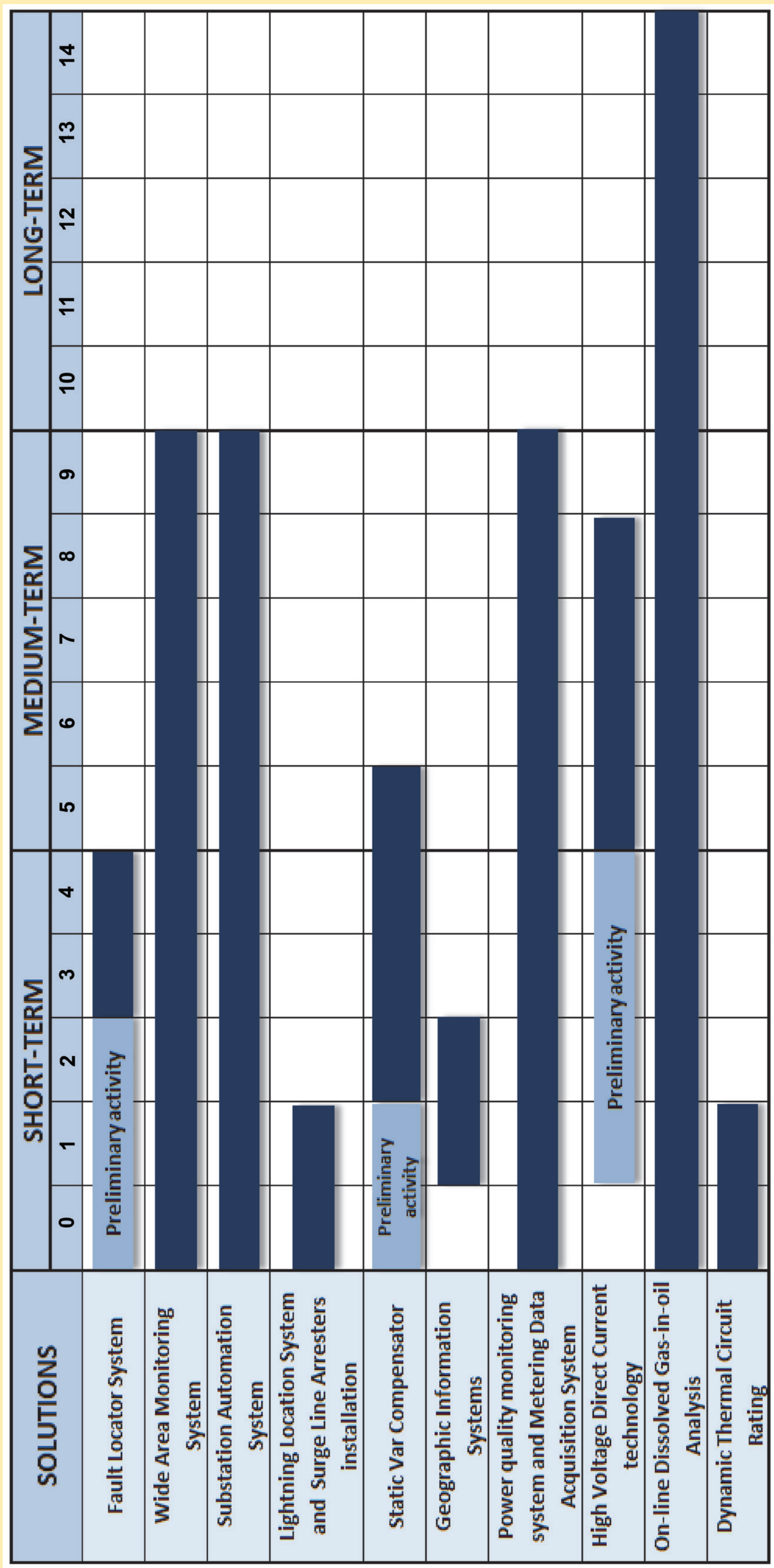
i. High Voltage Direct Current technology with the required preliminary studies and activities in the short term and completion in the medium term; and

j. On-line-Dissolved Gas-in-oil Analysis, already started, to be positioned in the short term and continued during the whole development of the roadmap.

The positioning within a fixed time frame creates a starting point for the initiatives, and it is very likely that the implementation process for some solutions will take more than five years. For example, the full development of SAS, already commenced and therefore considered a short-term initiative, will conclude in about ten years. Equally, the full implementation of WAMS, the Power quality monitoring system and the Metering Data Acquisition System, which are tied to the installation of new substations, will also conclude the same ten year period.

Figure 83 shows the final time positioning of the Smart Grid initiatives.

FIGURE 83: FINAL TIME POSITIONING OF SMART GRID INITIATIVES



Source: Authors

C. Introduction

C.1 General Overview

The technical analysis report has identified a number of Smart Grid initiatives that are appropriate for Vietnam. These solutions have been prioritized after a technology-focused investigation but no evaluation about their costs and economic benefits has yet been performed.

The aim of this document is to identify the costs and benefits of each Smart Grid solution and to evaluate their economic parameters in order to understand the real added value of each initiative.

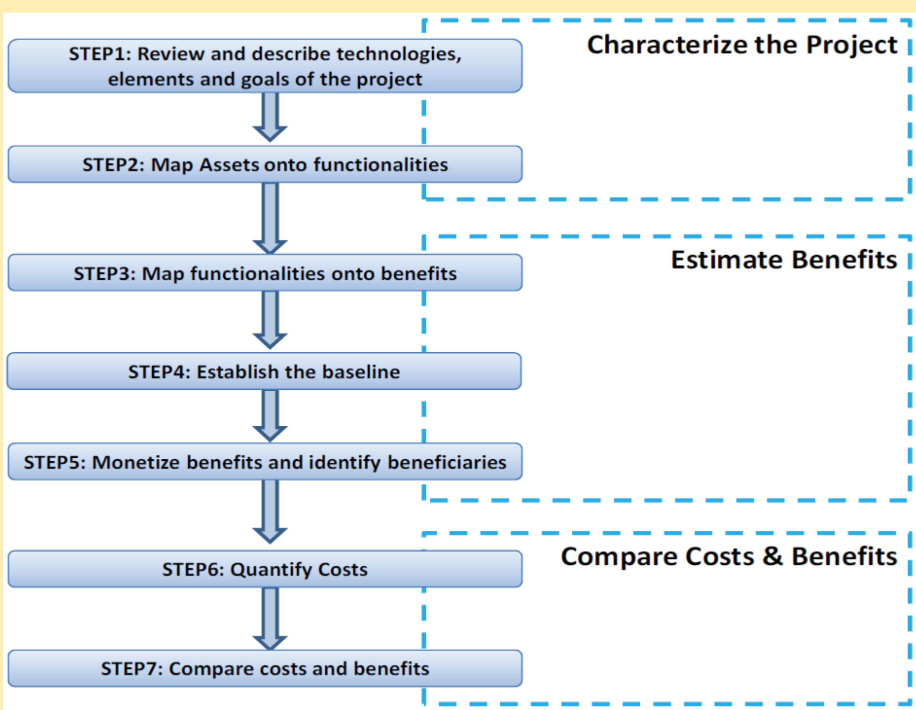
The Cost-Benefit Analysis (CBA) is based the key steps of the "Guidelines for conducting a cost-benefit analysis of Smart Grid projects" suggested by the Joint Research Centre Institute for Energy and Transport (JRC). This methodology offers an effective way of creating a set of guidelines for tailoring assumptions to local conditions, for identifying and assessing financial benefits as well as costs and for performing a sensitivity analysis of the most critical variables.

Based on the JRC approach [1] the CBA offers an economic analysis divided into three phases.

The first phase consists of a definition of the boundary conditions (demand growth forecast, discount rate, local grid characteristics, etc.). The second phase uses a "seven step approach" as shown in Figure 84.

The third phase the Cost and Benefits analysis refines the process by changing the critical parameters of each project in order to find the best and most balanced Smart Grid strategy. Towards this end, a sensitivity analysis of the major variables is performed in order to evaluate the deviation of the analysis results.

FIGURE 84: COSTS & BENEFITS ANALYSIS STEPS



Source: JRC, 2012, (1)

This is followed by a risk analysis that weighs the risk impact and related likelihood of its occurrence for all the Smart Grid initiatives.

Finally, based on the information and results obtained from the CBA and the risk analysis, it is possible to define the final prioritization of Smart Grid initiatives and a resultant phased implementation plan.

C.2 Document Structure

This report is structured in four main parts.

The first part, comprised of chapter 'D', identifies the key elements necessary to perform the Cost-Benefit Analysis. This chapter describes the structure of the cost and benefits analysis, identifies assessed benefits as well as costs and then articulates the main assumptions made about the Vietnamese transmission system.

The second part, composed of chapters 'E' and 'F', aims to identify and quantify the benefits and costs of each Smart Grid solution. These two chapters articulate the main assumptions and the basic reasons for setting up the implementation scenarios of the various Smart Grid initiatives. In particular chapter 'E' is focused on benefits. It associates initiatives with functionalities and then functionalities with commensurate benefits as well as quantifying each of these Smart Grid solution benefits. Chapter 'F' addresses cost estimations for the development of each Smart Grid initiative.

The third part, composed of chapters 'G' and 'H', finalizes the analysis by comparing the costs and benefits of each solution and evaluating different implementation scenarios. Chapter 'G' compares costs and benefits (identified and quantified in the previous chapters) and estimates some economic indicators for each Smart Grid initiative. Chapter 'H' performs some sensitivity analyses that evaluate different implementation scenarios for the various Smart Grid solutions, in order to understand the best time horizon of their development and to determine the best deployment strategy.

The fourth part, composed of chapters 'I' and 'J', performs the risk analysis and exploits the intelligence gathered from the preceding sections (together with the results of CBA) to carry out the final prioritization of the Smart Grid initiatives. In particular, chapter 'I' identifies the risks related to each. Finally, chapter 'J' presents the refined prioritization of all the Smart Grid initiatives, positions them on a timeline, suggests the best starting point for the solutions and recommends a suitable elapsed time for their development.

D. Cost-Benefit Analysis Structure and Base Assumptions

D.1 Key Points Summary

The proposed Smart Grid solutions for NPT have been modeled to assess their profitability in terms of costs and benefits. The present chapter aims to identify the key elements necessary to perform the Cost-Benefit Analysis, which it does by defining the benefits (direct and system level) and costs (CAPEX and OPEX) that have to be considered.

The Business Case is based on a Discounted Cash Flow (DCF) method, with final results presented for a period of 15 years (2016-2030), assuming a discount rate of 10%.

The Business Case has assumed a green field starting point for each initiative despite the fact that some are already in progress.

To create a starting point for this analysis it is crucial to understand the baseline scenario and the expected growth rate of the Vietnamese transmission system. This chapter identifies some base assumptions shared with and approved by the Vietnamese stakeholders[1] and are shown in Table 22.

The Business Case Model compares the Net Present Value of the Smart Grid applications. The model

TABLE 22: SMART GRIDS BUSINESS CASE—SUMMARY OF BASE ASSUMPTIONS

Topic	Major assumptions
• Peak demand	• Baseline data (2015) in GW: 22.5 (source: NLDC). • The average peak load growth rate over a 15 year timeframe is +9%/year (source: NLDC).
• Consumption	• Baseline data (2015) in TWh: 161 (source: NLDC). • Growth rate over a 15 year timeframe is 7-8%/year (source: NLDC).
• Number of customers	• Baseline data (2012) equal to 19.781 million, with 18.564 million residential customers, 391,493 commercial customers, 53,296 Agricultural, 518,610 industrial customers and 253,919 others. • Growth rate over a 15 year timeframe is 8%.
• Power capacity	• Baseline data (2015) of installed capacity in GW: 33 GW (source: NPT). • 2030 installed capacity: 146.8 GW (source: NPT) of which: o Hydropower accounts for 11.8%; o Energy storage hydropower for 3.9%; o Coal thermal power for 51.6%; o Gas fired power for 11.8% (of which LNG for 4.1%); o Power using renewable energy for 9.4%; o Nuclear power for 6.6%; o Imported power for 4.9%.
• Transmission network sizing	• Transmission lines (source: NPT-NLDC): o 500kV: 6,756 km (2014), ~+16%/year growth rate (average in period 2009 – 2014). o 220kV: 12,513 km (2014), ~+6.6%/year growth rate (average in period 2009 – 2014). • Transmission substations: o 164 (2015), ~+7% new substations/year. • Transformers (source: NPT-NLDC): o 500kV: 21,900 MVA (2014), ~ +32% per year. (average in period 2009 – 2014). o 220kV: 31,351 MVA (2014), ~+15% per year. .(average in period 2009 – 2014).
• Transmission network performances	• SAIFI: 27.975 in 2013 (source: EVN estimation). • SAIDI: 4,461 minutes in 2013 (source: EVN estimation). • Network losses equal to 2.49%, whose technical assumed 70% and non-technical 30% (source: NPT). • The total cost for system operation is $400,000,000 per year (source: NPT, 2014).

Source: Authors

can simulate a number of scenarios to reflect possible changes in the speed of the roll-out, predicted savings/ benefits, estimated costs for key items (i.e. Smart Grid new technologies and devices). Some of the key information has been taken from the NPT local environment, whilst others have been sourced from international references.

The specific Business Cases that are illustrated in detail in the following sections separately considers:

a. **Benefits** linked to the deployment of such technologies associated with either reducing costs or raising revenues and are divided into:
   i. **Direct**, if connected to Smart Grid solutions and directly realized by the operators responsible for such initiatives (under the current market structure);
   ii. **System level**, if not supported directly by Smart Grid solutions but a cumulative function of other Smart Grid applications and not directly realized by the operators.
b. **Costs**, in terms of capital (**CAPEX**) and operating expenditures (**OPEX**), needed respectively for the design, purchase, installation etc and to operate once installed and commissioned (the value of asset not yet depreciated is considered in the terminal value calculation).

D.2 Description of Assessed Benefits and Costs

The implementation of the transmission network Smart Grid solutions offers a wide-range of benefits for the whole electrical system.

The Business Case verifies the sustainability of the Smart Grids solutions proposed for Vietnam and considers the benefits both direct and at system level:

a. **Direct benefits**, which can be achieved by operators:
   i. **Reduced operating costs of T&D System**. Reduction/optimization of resources involved in the manual operations and maintenance of the electrical grid enabled by the implementation of Smart Grid solutions;
   ii. **Improved quality of services and losses**. Reduction of technical losses on the electrical networks due to automated control of grid voltage and power factor systems, optimization of load dispatching and management;
   iii. **Increased continuity of service**. Improved reliability from automated responses to some types of outages and faster identification and repair of those that do occur thus reducing the duration or scale of outages.
b. **System level benefits** that can be generated for the whole electrical system and are based on the development of alternative energies in particular distributed renewable sources enabled by some of the Smart Grid solutions. The benefits are:
   i. **Optimized energy generation mix and peak reduction**. Renewable energy sources will result in lower CAPEX and OPEX costs, as there will be no need for new conventional fossil fuel power stations to cover peak demand. The need for conventional fossil fuel power plants is expected to decrease noticeably over the next years due to further innovations and technology maturity;
   ii. **Increased fuel availability**. Given that Vietnam has limited natural coal sources this reduction in conventional fossil fuel power stations will result in a reduction of coal imports and enable the sale of their own coal output at international prices;
   iii. **Reduced GHG emissions**. Again, the reduction in conventional fossil fuel power stations will result in lower emissions of GHG (CO_2). This reduction will mean that Vietnam will meet its own carbon footprint reduction targets and facilitate a positive trade in GHG emission certificates to those nations unable to reduce their carbon footprint to internationally agreed levels.

The following aspects have been considered in relation to the cost of Smart Grid applications:

a. **Transmission system CAPEX**, includes:

i. Procurement of transmission network equipment for installation on the grid including transmission line sensors, HVDC terminals, SVC devices, and phasor measurement technology for wide area monitoring;

ii. Cost of enterprise back-office systems and associated hardware (including outage and transmission management); and

iii. Cost of supporting IT/Cyber Security and communications infrastructure for transmission lines to substations.

b. **Transmission system OPEX**, including cost of maintenance and operations of the above mentioned automation systems and equipment.

D.3 Assumptions

The Business Case for Smart Grid solutions has been developed based on specific assumptions about the expected growth and evolution of the electrical transmission system (in a business as usual scenario) and on the benefits and costs as described in the previous section 'D.2'.

Such assumptions are based on public institutional sources for Vietnam's electrical system and, where unavailable, the consultant's direct project experiences mindful of the knowledge and/or perception of the particular requirements of the Vietnamese systems.

It is important to outline that all assumptions have been submitted to and approved by the Vietnamese stakeholders and decision makers in order to ensure consistency with local market characteristics and projects already underway in the country.

The following assumptions are based on the current status of the electrical system and expected development in a business as usual scenario.

The next section presents assumptions that refer to the characteristics of the Vietnamese transmission system. The specific identification and quantification of benefits regarding the proposed Smart Grid initiatives are detailed in chapter 'E'. The same investigation about Smart Grid initiatives costs are carried out in chapter 'F'.

D.3.1 Discount rate

At the outset it is important to assume a discount rate value in order to compare the Net Present Value of the Smart Grids application components. The calculation below uses the assumed Discount rate and Weighted Average Cost of Capital (WACC):

$$WACC = r_d \times \frac{D}{D+E} + r_e \times \frac{E}{D+E}$$

where:

a. r_d = cost of debt;

b. r_e = cost of equity;

c. D = market value of debt; and

d. E = market value of equity.

For Vietnam the following values have been assumed:

a. r_d = 6.5%. The yields on comparably rated bonds with maturity periods similar to the timescales of the investment has been adopted;

b. $r_e = r_d$ + 5.3%. This uses the bond yield value plus a risk premium of 5.3% as a means of estimating the cost of equity;

c. $\frac{D}{D+E}$ = 33%. Debt-to-total capitalization ratio; and

d. $\frac{E}{D+E}$ = 67%. Equity-to-total capitalization ratio.

The discount rate is estimated to be 10%.

D.3.2 Timeline and pace of implementation

A timeline of 15 years (2016-2030) has been proposed for the implementation of the identified Smart Grids solutions as per the Vietnamese roadmap.

The implementation pace of the Smart Grid applications is based on the particular characteristics and architecture.

D.3.3 Peak demand

The anticipated peak load for 2015 is estimated at 22.5 GW.

The average peak load growth rate over a 15 year period is predicted to be ~+9%/year.

D.3.4 Consumption

The anticipated electricity consumption in 2015 is estimated at 161 TWh.

The average growth rate in electricity consumption over a 15 year timeframe is predicted to be 7%–8%/year.

D.3.5 Number of customers

In 2012 there were 19.781 million customers of which 18.564 million were residential, 391,493 were commercial, 53,296 were agricultural and 518,610 industrial customers with 253,919 others.

The growth rate in the number of customers over a 15 year period is predicted to be 8%.

D.3.6 Power capacity

The total installed power capacity for 2015 is estimated at about 33 GW while the installed capacity in 2030 has been predicted at about 146.8 GW. The combination of alternative and conventional technologies will be:

a. Hydropower at 11.8%;

b. Energy storage hydropower at 3.9%;

c. Coal thermal power at 51.6%;

d. Gas fired power at 11.8% (of which LNG will be at 4.1%);

e. Power using renewable energy at 9.4%;

f. Nuclear power at 6.6%; and

g. Imported power at 4.9%.

D.3.7 Transmission network sizing

The eventual size of the transmission network in Vietnam by 2030 is based on the following assumptions:

a. Based on the period between 2006–2014 the average growth rate for various elements of the transmission network in Vietnam are predicted to be:

   i. 500kV: 6,756 km (2014), ~+16%/year growth rate;

   ii. 220kV: 12,513 km (2014), ~+6.6%/year growth rate;

b. Transmission substations: 164 (2015), ~+7% new substations/year;

c. Transformers—The growth rate for these is based on the period from 2009 to 2014:

   i. 500kV: 21,900 MVA (2014), ~+32% per year;

   ii. 220kV: 31,351 MVA (2014), ~+15% per year.

D.3.8 Transmission network performances

The major indicators of service levels in an electrical network are **SAIFI** and **SAIDI**:

a. **SAIFI** (System Average Interruption Frequency Index) is the count of all extended outages over the number of customers;

b. **SAIDI** (System Average Interruption Duration Index) is the sum of all outage durations over the number of customers.

During 2013 the SAIFI and SAIDI values for the Vietnamese transmission were respectively 27,975 interruption events for a total of 4,461 minutes.

Transmission network losses on the Vietnamese network were running at 2.33% in 2015 distributed between technical and non-technical losses, which are estimated to be running at 70% to 30% respectively. These percentages are based on international experiences as this data is unavailable from the Vietnamese network.

In 2014 the total cost of system operation is estimated to be $400,000,000 per year (source: NPT).

E. Identify and Quantify Benefits

E.1 Key points summary

Following the JRC methodology, the first step of the cost benefit analysis is to map the identified Smart Grid initiatives to their functions within the transmission system. The second step is to map the function served to the benefit achieved from the Smart Grid application. This chapter performs these mappings in order to identify the specific range of benefits for each Smart Grid initiative.

For each Smart Grid initiative, it has been possible to quantify these direct benefits:

a. Direct Transmission OPEX reduction;
b. Reduction of energy not served;
c. Reduction of power losses;
d. Improved system reliability through a reduction in the frequency of system faults and their duration; and
e. Avoided CAPEX for transmission system and Deferred Capacity Investments.

To quantify the financial value of such benefits, some assumptions have been made for each Smart Grid initiative. These assumptions have been made by the consultant based on international experience and has been shared and discussed with the Vietnamese stakeholders prior to the analysis (during the meetings of the discovery process from April 21st to April 23rd 2015). These statements are summarized in Table 23.

Not only direct benefits have been investigated but also system level ones. Regarding them some considerations have been done; their monetization has not been investigated for each Smart Grid initiative, but it has been estimated in connection with the deployment of Smart Grid initiatives.

The support to the integration of renewable energy generation allowed by Smart grid development has been also analyzed. International experience, in fact, demonstrates that Smart Grid solutions can facilitate the integration of RES whilst limiting the need for additional infrastructure and improving the system operation. The contributions of the different Smart Grid initiatives are described, stating that HVDC technology and Dynamic Thermal Circuit Rating can be considered the best ones in terms of new variable renewable generation integration.

Finally, the benefits in blackout prevention achievable with the deployment of Smart Grids are also investigated. The international experience and also the Vietnamese one regarding the cost and damages derived from a blackout are important and these were the main drivers that pushed the development of Smart Grids technologies in USA, Europe and around the world. The benefits derived from blackout prevention were considered but separately.

E.2 Mapping Assets to Functionalities

Starting from the main categories of functionalities described in JRC methodology, four of them have been selected to be use in this analysis. Each of them has been divided in sub-functionalities, which are tailored to the Vietnamese specific Smart Grid roadmap context. These functionalities and the relative sub-functionalities are:

a. Enhancing efficiency in day to day grid operation, composed by:
    i. Enhance network stability;
    ii. Enhance efficiency in asset maintenance; and
    iii. Enhance efficiency in system operation.
b. Ensuring network security, system control and quality of supply, composed by:
    i. Enhance network automation;
    ii. Enhance network power quality; and
    iii. Fault reduction.
c. Better planning of future network investment, composed by:
    i. Enhance network development flexibility;
    ii. Dispatching constraints reduction;
    iii. Congestion reduction; and
    iv. Upgrade network asset.
d. Improving market functioning and customer service, composed by:
    i. Facilitate market development.

Table 24 maps the Smart Grid initiatives proposed in the technical analysis report with the functionalities that they perform in the transmission system.

TABLE 23: SUMMARY OF BENEFITS MONETIZATION ASSUMPTIONS ON SMART GRID INITIATIVES

Initiative	Major assumptions regarding benefits
SAS	• The SAS installation can contribute 60% to the global reduction of the OPEX for the transmission system. • Average ENS reduction of 100 MWh per year for each substation equipped with SAS. • The ENS costs is 3,000 $/MWh.
WAMS	• WAMS installation can contribute 10% to the global reduction of the OPEX for the transmission system. • The total number of voltage collapse events account for about 10% brownout of the peak load per year amounting to a total of 30 minutes. • The prevention capacity is directly proportional to the pace of installation. • All the new substations brought on-line and 68 of the existing ones will be equipped with PMUs. • WAMS functions capable of ensuring the prevention of such events will be available 3 years after the project commences. • This application will result in a 20% reduction in the number of voltage collapse events if all substations have PMUs installed.
Lightning Location System	• Lightning Location System installation can contribute 5% to the global reduction of the OPEX for the transmission system. • The phase-to-phase-to-ground faults caused by lightning account for 8% of the total number of the faults caused by lightning. • These events account for about 2% brownout of the peak load per year amounting to a total of 30 minutes. • This application will result in a 25% reduction of phase-to-phase-to-ground faults caused by lightning. • The ability to prevent such events will be available after 3 years from the start of the project.
SVC	• SVC installation can contribute 10% to the global reduction of the OPEX for the transmission system. • The total number of voltage collapse events cause approximately10% of brownouts of the peak load per year accounting for a total of 30 minutes. • This application will result in a 25% reduction of the number of voltage collapse events.
HVDC	• A HVDC link can contribute 5% to the global reduction of the OPEX for the transmission system. • 500 kV and 2000 MW rated power for both AC and HVDC solution. • AC and HVDC lines have the same length. • The OPEX is calculated at 1.5% of the capital expenditure for both AC and HVDC lines. OPEX for converter stations is 3% of their CAPEX (source: manufacturers).. • Yearly energy losses are calculated with the following formula: o L_year=8760 LF X L_Pmax, where: o LF = 70% is the loss factor, corresponding to 6,132 equivalent hours; o L_Pmax are the losses at rated power and depend on the type of the transmission (AC or HVDC) and the size of the conductors. • The financial value of energy losses is estimated to be 60 $/MWh per year. • The annual financial value of the reduction of power losses is based on the difference between the value of AC and HVDC energy losses per year.
FLS	• These events account for about 10% brownout of the peak load per year amounting to a total of 30 minutes. • The prevention capacity is directly proportional to the number of lines equipped with FLS devices. • This application will result in a 25% reduction of time lost because of faults.
DGA	• Average cost of a transformer fault is approximately $9,000 per MVA and the fault probability is estimated to be about 0.6%. • The installation of this device in transformers will prevent about 80% of faults.
Dynamic Thermal Circuit Rating	• Dynamic Thermal Circuit Rating can contribute 5% of the OPEX for the transmission system. • It is proposed that four critical lines be equipped with DLR sensors. • These lines are 100km in length. • The costs estimated for these four lines include the cost of the DLR solution (1 sensor every 10km) and of reconductoring. • A DLR sensor costs $32,000 while the reconductoring costs $200,000/km.
GIS	• It is assumed that the GIS application will only be developed for the SAS initiative and it is expected to result in a 10% reduction in the OPEX for the SAS project.
Power quality monitoring and Metering Data Acquisition Systems	• Power quality monitoring and Metering Data Acquisition Systems can contribute 5% to the global reduction of the OPEX for the transmission system.. • The fault events caused by critical voltage dips account for about 1% brownout of the peak load per year amounting to a total of 15 minutes. . • The prevention capacity is directly proportional to the number of lines equipped with PQ devices.. • This application will result in a reduction of fault time losses with Power Quality monitoring is about 20%.

Source: Authors

TABLE 24: MAPPING ASSET TO FUNCTIONALITIES

FUNCTIONALITIES	Enhancing efficiency in day-to-day grid operation			Ensuring network security, system control and quality of supply			Better planning of future network investment				Improving market functioning and customer service
SMART GRID SOLUTIONS	Enhance network stability	Enhance efficiency in asset maintenance	Enhance efficiency in system operation	Enhance network automation	Enhance network power quality	Fault reduction	Enhance network development flexibility	Dispatching constraints reduction	Congestion reduction	Upgrade network asset	Facilitate market development
Substation Automation System		•		•		•				•	
Wide Area Monitoring System	•		•			•				•	
Lighting Location System			•		•	•					
Static Var Compensator	•		•				•	•	•		
High Voltage Direct Current technology	•						•	•	•		
Fault Locator System		•									
Power quality monitoring system			•		•	•				•	
On-line Dissolved Gas-in-oil Analysis		•				•				•	
Dynamic Thermal Circuit Rating			•				•	•	•	•	
Geographic Information Systems		•	•								
Metering Data Acquisition System			•							•	•

Source: Authors

For each initiative, the reasons for this mapping are:

a. **Substation Automation System (SAS).** It is evident that this initiative "Enhances network automation" and consequently "Enhances efficiency in asset maintenance". Further, it "Upgrades network asset" thanks to the installation of new components (i.e. IED). Finally, as stated in the technical analysis report, SAS monitoring capacity leads to a "Fault reduction".

b. **Wide Area Monitoring System (WAMS).** Thanks to the monitoring application that can be developed using PMUs data, WAMS initiative can "Enhance network stability" (both voltage and transient stability) and also can "Enhance efficiency in system operation". As in SAS case, the installation of new devices "Upgrade network asset". In the end, with a successful exploitation of WAMS functions it is possible to achieve a consistent "Fault reduction".

c. **Lightning Location System.** The main purpose of this solution is the "Fault reduction", thanks to its capacity to avoid transient faults due to lightning. Transient faults reduction allows to

"Enhance network power quality" Further, the availability of a Lightning Location System data in remote control and dispatching centers can "Enhance efficiency in system operation".

d. **Static Var Compensator (SVC)**: A proper installation and exploitation of SVC devices can "Enhance network stability" (as for WAMS case, both voltage and transient stability) and also can "Enhance efficiency in system operation". Moreover, this technology allows achieving a "Dispatching constraints reduction" and a "Congestion reduction"; such reductions remove constraints from network growing process and so "Enhance network development flexibility".

e. **High Voltage Direct Current (HVDC) technology**: Building an HVDC link allows achieving a "Dispatching constraints reduction" and a "Congestion reduction"; such reductions remove constraints from network growing process and so "Enhance network development flexibility".

f. **Fault Locator System**. This initiative can contribute to time and cost reduction of asset maintenance, therefore its main functionality is to "Enhance efficiency in asset maintenance".

g. **Power quality monitoring system**. The main purpose of this initiative is to "Enhance network power quality" and consequently to "Enhance efficiency in system operation". Moreover, as stated in the Technical Analysis report, a suitable KPI is the percentage reduction of voltage deeps and in some cases these events can cause outages. Consequent, one of most important functionalities of this initiative is "Fault reduction". Finally, the installation of new devices allows to "Upgrade network asset".

h. **On-line Dissolved Gas-in-oil Analysis (DGA)**. The installation of the DGA monitoring devices "Upgrade network asset". Their prevention capability of transformer faults allows achieving transformer "Fault reduction" and consequently to "Enhance efficiency in asset maintenance".

i. **Dynamic Thermal Circuit Rating (DTCR)**: This initiative, increasing line "ampacity", allows achieving a "Dispatching constraints reduction" and a "Congestion reduction"; such reductions remove constraints from network growing process and so "Enhance network development flexibility". Moreover, this constraints reduction allows to "Enhance efficiency in system operation".

j. **Geographic Information Systems (GIS)**: The availability of a GIS for initiative for asset management and/or system operation allows to "Enhance efficiency in asset maintenance" and to "Enhance efficiency in system operation".

k. **Metering Data Acquisition System**. This measurement system is a key element and an enabling technology for the achievement of an open energy market, so its main functionality is "Facilitate market development". Consequently the availability of such measurements allows to "Enhance efficiency in system operation". Finally, the installation of new devices allows to "Upgrade network asset".

E.3 Mapping Functionalities to Benefits

For the second step, five transmission system benefits have been identified to map the functionalities of Table 24. These benefits derive from the generic direct benefits (see section 'D.2') and from JRC methodology, but they have been properly tailored to the specific Smart Grid roadmap context, in order to fit Vietnamese global policy targets in the electricity sector. These benefits are:

a. **Direct Transmission OPEX reduction** (automation and operational efficiency). Regarding the optimization of operating costs due to automated operations reported savings ranging between -5% and -10% have been assumed considering international experiences (e.g. Italian case, feasibility study performed in Serbia and ECRA project in Smart Grids[2]). Such benefits can of course vary significantly according to specific network characteristics and architecture, intensity and productivity of resources involved in network operations and maintenance and level of provided service. The literature on this issue is quite poor and a detailed study would be necessary to obtain the exact value of expected Direct Transmission OPEX reduction for Vietnam. Such exhaustive analysis is outside the scope of this work, so a conservative estimation of this value can be considered functional to the benefits monetization performed in this CBA. Therefore, relying on consultant experience earned in dealing with similar international projects, and taking into account the Vietnamese scenario, the value of operating cost reduction potentially allowed by a Smart Grid development has been assumed equal to -8%. The various Smart Grid initiatives contribute in different ways to achieve this objective; the estimations of their contribution are described in paragraph 'E.4'. To perform such estimation the potential impact of the different initiatives has been evaluated, assigning the highest contribution to SAS because this Smart Grid application involves a large amount of people working on the transmission network. To some other initiatives, like WAMS or LLS, a lower value has been assigned because they involves only resources (in terms of people and money) related to remote control center.

b. **Reduction of energy not served**: This benefit considers the prevented Energy Not Served (ENS), which is a typical KPI considered in Cost-Benefit Analyses. The procedure to monetize is described in paragraph 'E.4.1'.

c. **Reduction of power losses**. The reduction of technical losses on the electrical transmission network due to automated control of grid voltage and power factors systems, optimization of load dispatching and management has been assumed equal to -10% of technical losses value (a more ambitious figure would be 20%), according to international experiences. Assuming technical losses equal to 1.63% of energy consumption such losses are therefore assumed to reduce by 0.16% at the end of the 15 years period. This statement sets up a reliable objective for the whole Smart Grid roadmap implementation, but in this CBA the monetization of the reduction of power losses has been considered only for HVDC initiative (see paragraph 'E.4.6').

d. **Improve system reliability through reduced frequency and duration of system faults.** This benefit considers the reduced duration and frequency of outages due to automated responses to some types of faults and faster scouting and repair for others. To evaluate this improvement in reliability of power supply the values proposed in the "DECISION: APPROVAL OF SMART GRID DEVELOPMENT PROJECT IN VIETNAM, November 2012" has been considered. This document assumes that, after each 5 years period, the Smart Grid development allows the following potential reduction:

    i. System average interruption frequency index (**SAIFI**) will be reduced 10%; and

    ii. System average interruption duration index (**SAIDI**) will be reduced 20%.

e. This benefit, thanks to the reduction of duration and frequency of outages, allow a reduction of **Energy Not Served** (**ENS**), which can be monetized as in "**Reduction of energy not served**" case.

f. **Avoided CAPEX and Deferred Capacity Investments**. The implementation of Smart Grid initiatives provides the transmission network of function and devices that can solve incident issues definitely or for a consistent time interval (some years). In the first case the Smart solution fixes the problem completely, so it is possible to identify an "**Avoided CAPEX**" benefit, shunning an investment in conventional transmission network components (e.g. lines, power plants, etc.). In the second case the Smart solution is not definitely but can put off to a later time an investment, therefore it possible to identify this benefit as "**Deferred Capacity Investments**".

Table 25 maps the functionalities identified with the benefits just listed. For each sub-functionality, the reasons for this mapping are:

a. **Enhance network stability**. This functionality aims to increase transmission network reliability both in terms of "Reduction of energy not served" and of "Improving system reliability through reduced frequency and duration of system faults".

b. **Enhance efficiency in asset maintenance**. This functionality aims achieving a "Direct Transmission OPEX reduction" thanks to the increased automation efficiency.

c. **Enhance efficiency in system operation**. This functionality aims achieving a "Direct Transmission OPEX reduction" thanks to the increased operational efficiency.

d. **Enhance network automation**. This functionality increases automation efficiency and so allows a "Direct Transmission OPEX reduction". Further it aims to increase transmission network reliability both in terms of "Reduction of energy not served" and of "Improving system reliability through reduced frequency and duration of system faults".

e. **Enhance network power quality**. Like "Enhance network stability" functionality also this one aims to increase transmission network reliability both in terms of "Reduction of energy not served" and of "Improving system reliability through reduced frequency and duration of system faults".

f. **Fault reduction**. Thanks to fault reduction it is possible to increase transmission network reliability both in terms of "Reduction of energy not served" and of "Improving system reliability

TABLE 25: MAPPING FUNCTIONALITIES TO BENEFITS

FUNCTIONALITIES	Enhancing efficiency in day-to-day grid operation			Ensuring network security, system control and quality of supply			Better planning of future network investment				Improving market functioning and customer service
BENEFITS	Enhance network stability	Enhance efficiency in asset maintenance	Enhance efficiency in system operation	Enhance network automation	Enhance network power quality	Fault reduction	Enhance network development flexibility	Dispatching constraints reduction	Congestion reduction	Upgrade network asset	Facilitate market development
Direct Transmission OPEX reduction (automation and operational efficiency)		•	•	•		•		•	•	•	•
Reduction of energy not served	•			•	•	•		•	•		
Reduction of power losses								•	•		
Improve system reliability through reduced frequency and duration of system faults	•			•	•	•		•	•	•	
Avoided CAPEX and Deferred Capacity Investments							•	•	•	•	

Source: Authors

through reduced frequency and duration of system faults". Consequently a "Direct Transmission OPEX reduction" is achievable.

g. **Enhance network development flexibility**. This functionality, performed by some Smart Grid solutions that aim to reduce network topology constraints, facilitates electrical network growing process. So the main benefit is "Avoided CAPEX and Deferred Capacity Investments".

h. **Dispatching constraints reduction**. This reduction enhances efficiency in daytoday system operation allowing "Direct Transmission OPEX reduction" and "Reduction of power losses". Further, an easier dispatching can avoid the majority of critical situations to take place in the electrical network. Therefore, it is possible to increase transmission network reliability both in terms of "Reduction of energy not served" and of "Improving system reliability through reduced frequency and duration of system faults".

i. **Congestion reduction**. For the same reasons stated for "Dispatching constraints reduction", also this functionality carries out "Direct Transmission OPEX reduction", "Reduction of power losses", "Reduction of energy not served" and "Improving system reliability through reduced frequency and duration of system faults".

j. **Upgrade network asset**. The installation of new devices, necessary for some smart grid initiative deployment, can avoid or put off to a later time an investment on the electrical network. So the main benefit is "Avoided CAPEX and Deferred Capacity

Investments". Moreover, the efficiency of these update equipment allows a "Direct Transmission OPEX reduction" and "Improves system reliability through reduced frequency and duration of system faults".

k. **Facilitate market development**. The electrical market is comprised by different phases; among them there is the ancillary market which carries out a "Direct Transmission OPEX reduction", allowing to dispatch the most convenient power sources.

E.4 Benefits monetization

To conclude the benefit analysis it is fundamental to determine how these benefits are monetized. The following paragraph discusses the monetization of the reduction of "**Energy Not Served**". The subsequent paragraphs from 'E.4.2' to 'E.4.11' repeats this process for each Smart Grid initiative.

The NPT wish to implement both Power Quality monitoring and Metering Data Acquisition System. Whilst these two applications are quite different and independent, they are both able to use the same measuring device. Thus it is worth implementing both these applications as this will maximize the investment in the measuring devices which will be widely deployed across the Vietnamese power network.

Chapter 'G' balances the costs of each Smart Grid application with the benefits it will deliver and use the all the assumptions articulated in this section.

E.4.1 Monetization of Energy Not Served reduction

Prior to commencing the cost benefit analysis of each Smart Grid initiative, it is worth considering the value of lost load (VoLL), **usually measured in $ per Megawatt ($/MW)**, which is what happens every time there is a service interruption (i.e. brownout or blackout) duration.

This parameter provides a means of calculating the financial value of a reduction in Energy Not Served (ENS) (see Table 25, "**Reduced energy not served**"). The reduction of the regular outages and brownouts that occur on the Vietnamese network is one of the key outcomes expected of the Smart Grid development, which is why it is important to evaluate them in terms of financial benefits. The ENS value is a useful way of equating the power outages to a financial value which can then be translated into a return on investment over time.

Whilst the current average Vietnamese VoLL compares quite favorably with the mature transmission networks of Europe and the USA, the failures are frequent enough to hinder current industrial development. They are also a significant disincentive to new industrial investments as reported to Bloomberg by many sources from the Industrial Zones Management Authority ([2] [3] [4]). In this context the ENS or VoLL value is too high for the industrial sector despite the perception of the average residential customers.

The continuing growth of the Vietnamese industrial sector is placing an ever increasing load on the electrical network thus causing the ENS value to increase. The annual increase of peak load is currently running at +9% and is a trend that is expected to continue over the next 15 years. It is a simple economic truth that demand is directly proportional to value and as the demand for electricity by the Vietnamese industrial sector increases so does the value of that energy, which means that every outage increases the net value of income lost.

One of the key targets for the development of the Vietnamese transmission system is increased network availability and reliability. A country with a low VoLL is a clear signal that system reliability is not an issue and therefore there is no compelling case for Smart Grid initiatives. Conversely, a country with an increasing VoLL, like Vietnam, is in urgent need of Smart Grid applications in order to address the problem.

The importance of addressing the ENS issue is borne out by the experiences of both developing and developed countries [5]. The report calculates the monetary value of VoLL, i.e. ENS, and finds that it lies between 2 and 5k $/MWh for developing countries. Whilst Vietnam is a developing country, it is a "fast" developing country, far faster than any other developing country in Africa or Asia.

Therefore, given:

a. That international references for developing countries calculate the VoLL or the ENS to lie between 2 and 5k $/MWh;

b. That the current Vietnamese Smart Grid development roadmap aims to enhance network reliability;

c. That the current and emerging Vietnamese industrial sector is making considerable demands on the power network, which impacts the value of the ENS; and

d. It is reasonable to ascribe a value of **$3,000 per unserved MWh** for the whole CBA timeframe.

This begs the question as to whether this value should be applied as a flat rate or varied as a function of the duration of the power outage. Whilst most VoLL calculations do apply a fixed rate, some countries such as Brazil use a sliding scale, (a block decreasing or increasing mechanism) or even a curve that maps the variation of this value according to the duration of the interruption.

NARUC, or "The National Association of Regulatory Utility Commissioners" developed a method for evaluating the cost of ENS as a function of the outage duration [6]. This approach, which has been widely accepted by the electrical industry as a whole, takes the view that a short interruption has a higher relative cost than a long brownout.

Finally, the NARUC mechanism is used to weight the cost of an interruption depending on its duration. This approach has been applied to the value of 3,000 $/MWh assumed for the Vietnamese network in order to create a table of interruption duration against cost (see Table 26 below).

The values in this table have been graphed to provide an at-a-glance illustration of the interruption cost ($/MWh) as shown in Figure 85.

Chapter 'H' provides a sensitivity analysis of ENS cost which further refines the effect of such assumptions on the benefits conferred by the Smart Grid initiatives.

The following paragraphs (from 'E.4.2' to 'E.4.11') evaluate the benefits derived from Smart Grid solutions and how they will enable "**Reduced energy not served**" and "**Improve system reliability through reduced frequency and duration of system faults**".

In order to estimate the amount of ENS reduction for some of the initiatives it has been assumed that a definite type of regular fault event on the transmission network (e.g.: voltage collapse) causes a number of brownouts per year corresponding to a percentage of the peak load (e.g. 10%) that lasts a certain number of minutes (e.g. 30 minutes).

E.4.2 Substation Automation System (SAS)

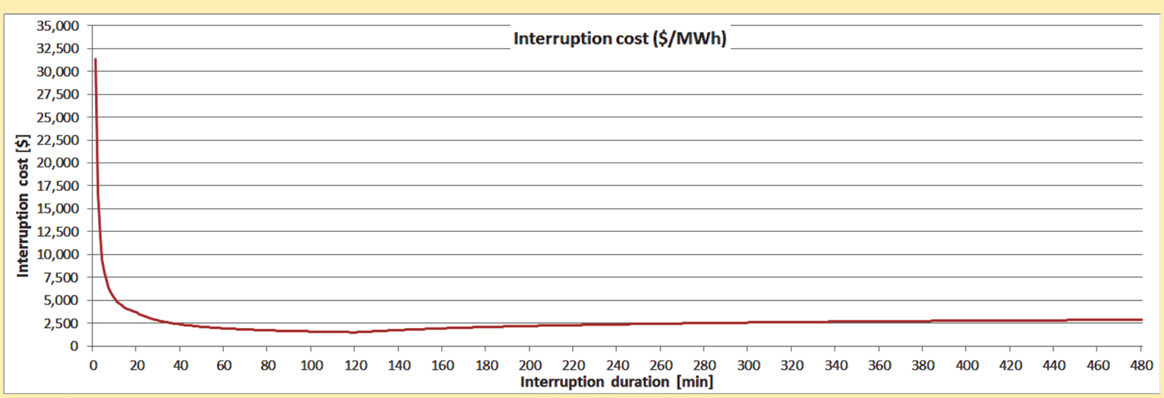
According to ERAV [7], the Vietnamese grid in general is not a modern system and has a low level of automation. Substation automation adds a lot of value and is a significant step in the direction of creating a more modern and reliable grid.

TABLE 26: INTERRUPTION COST DEPENDING ON INTERRUPTION DURATION

interruption duration (min)	interruption cost ($/MW)
1	522
20	1,215
120	3,000
240	9,459
480	22,914

Source: Authors

FIGURE 85: INTERRUPTION COST ($/MWH) DEPENDING ON INTERRUPTION DURATION



Source: Authors

The benefits of SAS functionality are:

a. Direct Transmission OPEX reduction; and

b. Improved system reliability through reducing frequency and duration of system faults.

Paragraph 'E.3' discussed a reduction of 8% in the OPEX for the transmission system and stated that a SAS installation can contribute up to 60% of this 8% of cost reduction, i.e. 4.8% of reduction. Given that the transmission system OPEX is $400,000,000 (according to NPT) then the expected reduction is $19,200,000. This 60% reduction value is the highest contribution to the global reduction of transmission system OPEX of all the proposed Smart Grid initiatives. This estimation is based on:

a. The consultant's experience gained from the Italian SAS project development;

b. The high cost overheads in terms of personnel and resources dedicated to the transmission network means that even a low reduction of such significant costs can lead to a sizable saving; and

c. As most of the Vietnamese substations are manually controlled, the advent of SAS will automate a large number of operations and controls leading to reduction of the OPEX costs.

The second benefit, as stated in the technical analysis report, is the key performance indicator (KPI) referring to the reduction of Energy Not Served (ENS). Toward this end, it has been assumed that:

a. An average value of annually ENS reduction per substation equipped with SAS is 100 MWh; and

b. The ENS costs according to what determined in paragraph 'E.4.1'.

This expected direct benefit of SAS is the prevention of faults or the reduction of the outage time (thanks to the automated and detailed diagnostic) at substation level with a consequent ENS reduction. Some evaluations of the Italian SAS, international experience [8] and the typical guaranteed performance of SAS device has led to estimating an average value of annually ENS reduction of 100 MWh per substation equipped with SAS. Since this value can change depending on the type of fault, 100 MWh represents a conservative estimation.

Therefore, it has been possible to estimate the benefits of this Smart Grid initiative in terms of "**Improve system reliability through reduced frequency and duration of system faults**".

E.4.3 Wide Area Monitoring System (WAMS)

The benefits of WAMS functionalities the consequent benefits are:

a. Direct Transmission OPEX reduction; and

b. Reduction of energy not served.

For the first one it has been assumed that WAMS can contribute up to 0.8% to the reduction of transmission system OPEX. The expected reduction is $3,200,000 based on a transmission system OPEX of $400,000,000 (information from NPT).

The overheads in terms of headcount and resources for WAMS are less than for SAS, so 0.8% (compared with SAS 4.8%) can be considered as a conservative and reliable estimation. Such evaluation is based on the experience earned from the Italian WAMS development.

For the second benefit, as stated in the technical analysis report, the evaluation of the success of WAMS initiative is very complex strictly dependent on the functions developed using PMU data. According to the USA experience of installing PMUs [9], the benefits are quoted to be much higher than the costs. This is despite the relatively high cost of $80,000 per PMU as they were among the first to adopt this technology.

A voltage stability monitoring feature based on WAMS [10] [11] can be considered a success if it helps to prevent 15%-35% of voltage collapses. The percentage depends on the topology of the portion of the network involved in the voltage instability event.

To estimate the benefits of the WAMS initiative in terms of "**Reduction of energy not served**" it has been assumed that:

a. The total number of voltage collapse events cause about 10% brownout of the peak load per year amounting to a total of 30 minutes;

b. The distribution variation of PMUs across the transmission network will result in varying levels of prevention of these events. The prevention capacity is directly proportional to the pace of installation (number of substation equipped with PMU);

c. All the new substations installed and 68 of the old ones will be equipped with PMUs; and

d. WAMS functions allowing the prevention such events will be available after 3 years from the beginning of the project (2015) and its prevention capacity is estimated to be 20% if all the substations are equipped with PMUs.

It is worth underlining that one of the Vietnamese transmission network issues is voltage stability [12]. Voltage collapse events are typical phenomena caused by this type of issue and though short in duration (conservative average 30 minutes) they can involve large areas of the transmission network (i.e. 10% brownout of the peak load per year). Such estimations are based on some outages that occurred in Italy. An effective prevention of voltage collapses can be performed only with online calculations and it is worth highlighting the value of WAMS based applications for this requirement. The real added value of WAMS in the prevention of voltage collapses is the up-to-date and accurate information together with the availability of phase measurements.

E.4.4 Lightning Location System (LLS)

The benefits of "Lightning Location System" functions are:

a. Direct Transmission OPEX reduction; and

b. Reduction of energy not served.

The first benefit is carried out by the availability of a Lightning Location System data in remote control and dispatching centers. It has been assumed this initiative can contribute to 0.4% of reduction of transmission system OPEX. This means 5% of the global 8% reduction as stated in paragraph 'E.3'. According information received from NPT the transmission system OPEX are equal to $400 million, the 5% of the expected reduction is equal to $1.6 million.

For the second benefit, as stated in the technical analysis report, it has been considered that thanks to Lightning Location System and the consequent Transmission Surge Line Arresters (TLSA) installation it is possible to reduce the transient faults caused by lightning. Willing to avoid the use of three phase reclosing (which creates great stresses to transformers and generators), the fault reduction allowed by this Smart Grid initiative could be useful in those cases in which the faults caused by lightning are phase-to-phase-to-ground, so they cannot be cleared by a single pole reclosing. Therefore, knowing that NPT will however install TLSAs, for the LLS benefit evaluation in term of "**Reduction of energy not served**" the incremental fault reduction achievable with a TLSA installation driven by a LLS is considered.

Thus, it has been assumed that:

a. The phase-to-phase-to-ground faults caused by lightning are about 8% of the total number of the faults caused by lightning;

b. These events cause an equivalent 2% brownout of the peak load per year lasting for a total elapsed time of 30 minutes;

c. The reduction of phase-to-phase-to-ground faults caused by lightning provided by a TLSA installation driven by LLS is 25% more than a generic equipping of lines with TLSAs; and

d. The ability to avoid such events will be available 3 years after the start of the project (2015).

It has not been possible to estimate the direct benefit of this solution in terms of "**Reduction of energy not served**". All these assumptions are based on the consultant's experience in designing, developing and supporting the operation of the Italian LLS [13].

E.4.5 Static Var Compensator (SVC)

The benefits of SVC functionality are:

a. Direct Transmission OPEX reduction; and

b. Reduction of energy not served.

For the first one it has been assumed that the SVC initiative contributes up to 0.8% of reduction of transmission system OPEX. This represents 10% of the global reduction of transmission system OPEX (starting at 8% based on the applications discussed up to that point as stated in paragraph 'E.3'). The expected reduction is equal to $3.2 million based on a transmission system OPEX of $400 million (information from NPT). This estimation is based on the European experience with SVC installation and this reduction is due to two main causes:

a. These devices operate on a "set and forget" principle; and

b. They allow more efficient and flexible daily network operations.

For the second benefit, as stated in the technical analysis report, is that such a system can effectively help to prevent 15%-35% of voltage collapses in the portion of the network influenced by its effects [14], [15], [16].

According to the NLDC, one of the difficulties for voltage regulation is that most of the shunt reactors are directly connected to the lines without circuit breakers, which causes inflexibility in the operation of the system. The NLDC is promoting research and development of switchable inductors and/or controllable compensators, like SVCs [17]. Additionally the seventh Master Plan also considers research on using FACTS, SVC devices in order to increase transmission limits and deliver a step change modernization of the control system [17].

The evaluation of the benefits of SVC is based on the conservative assumption that the total number of voltage collapses cause approximately 10% brownout of the peak load per year for an elapsed total time of 30 minutes. This solution will be considered a success if it is able to reduce the incidence of these events by 25%.

E.4.6 High Voltage Direct Current (HVDC) technology

According to the NLDC [18], there is certain to be more cooperation and power exchange with neighboring countries in the near future. Such interconnections will bring similar benefits by unifying regional sub-systems within a nation. Besides, this is also an opportunity to develop an inter-country power market, possibly between countries in the Indochina peninsula or even other Asian countries. However, interconnection with other countries may create new challenges for the operational systems in Vietnam.

The idea of promoting interconnection between the southern grid in China and the Vietnamese grid through HVDC at 500kV has been considered for few years. By using HVDC technology Vietnam hopes to resolve the current issue of operating disparate systems. At the same time, the power exchange with the neighboring countries will become safer [19] . Additionally, the seventh Master Plan also considers the possibility of having HVDC links and has established research programs for the development of transmission networks at voltage levels of 750 kV, 1,000 kV and HVDC for use after 2020 [17].

An incremental analysis has been performed for the evaluation of the HVDC initiative. It is not possible to do a full cost benefit analysis because the benefit derived from the installation of a new line is something to be determined on a case-by-case basis and cannot be generalized. But since the benefit of the new line, in terms of optimization of energy mix, is independent from the technology used (AC or DC), an incremental cost benefit analysis is really useful to understand the impact of the adoption of a DC line instead of an AC one. This also highlights the further benefits that derive from using DC technology instead of the traditional AC system. The construction of a new HVDC line is not a smart initiative in itself, rather the truly smart aspect is the choice of HVDC technology with its inherent features and characteristics for already planned links instead of using traditional AC lines.

Thus, a very conservative approach has been used that assesses the most appropriate technology for a link between currently independent power systems. The choice is between a legacy or "normal" AC system or one based on HVDC technology. This approach will ensure a robust solution appropriate for both current and predicted requirements.

The basis for the assessment is a conservative one as it considers only the <u>direct benefits</u>. Wider system level benefits are not internalized but it is important to highlight that HVDC technology is the <u>most versatile Smart Grid initiative</u> to integrate with <u>new variable renewable generation</u>. In fact the inherent increased transfer capacity and active power control of HVDC are fundamental benefits, which will allow the power generated from wind or solar power plants to be easily absorbed by balancing the natural fluctuation of renewables.

A comparison of the relative costs and benefits of the two technologies shows that HVDC has a higher initial install cost because of the converter stations, while the overhead lines or the cables are less expensive per kilometer. Additionally, HVDC lines become more cost efficient as the distance increases since the cost of the converter stations can be amortized over the line length. Given the higher install expense and lower line cost of HVDC over AC the break-even point will be related to the overall length of the link required.

The financial valuation of the direct technical benefits of HVDC are as follow;

a. The "**Reduction of power losses**". This benefit is strictly related to the lower cost per km of DC lines relative to AC ones. The lower cost allows a greater length and thus a lower resistance, which in turn reduces power losses;
b. The "**Direct Transmission OPEX reduction".** As the operational costs of the HVDC have been taken into account in the costs list, the corresponding OPEX of the AC line too has to be taken into account as a benefit. In addition, it has been assumed that the HVDC link can contribute 0.4% to the global reduction of the OPEX for the transmission system. The expected reduction is $1,600,000 considering a transmission system OPEX value of $400,000,000, a figure provided by NPT.
c. This estimation is based on the consultant's broad experience with HVDC as well as its greater efficiency and flexibility for daily network operations.

The incremental costs of the HVDC link relative to the HVAC solution are described in chapter 'F', while the main assumptions for calculating and estimating the reduction of power losses benefit are as follows;

a. 500 kV and 2,000 MW rated power for both AC and HVDC solution;

b. AC and HVDC lines have the same length;

c. Converter stations losses are 1.2% at rated power;

d. The sizing of the conductors is optimized separately for AC and HVDC. The sizing of the section is made by balancing of the investment cost of the line with the cost of losses over 15 years (optimum conductors to minimize investment plus capitalized cost of losses);

e. Yearly energy losses have been calculated using the following formula:

$$L_{year} = 8760 \times LF\, L_{Pmax}$$

where:

iii. LF = 70% is the loss factor[3], corresponding to 6,132 equivalent hours[4];

iv. L_{Pmax} are the losses at rated power and depend on the type of the transmission (AC or HVDC) and the size of the conductors.

f. Energy losses have been valued at 60 $/MWh for the annual energy losses as depicted in the histogram shown in Figure 86 below.

g. The financial value of the annual power loss reduction is the difference between the cost of AC and HVDC annual energy losses.

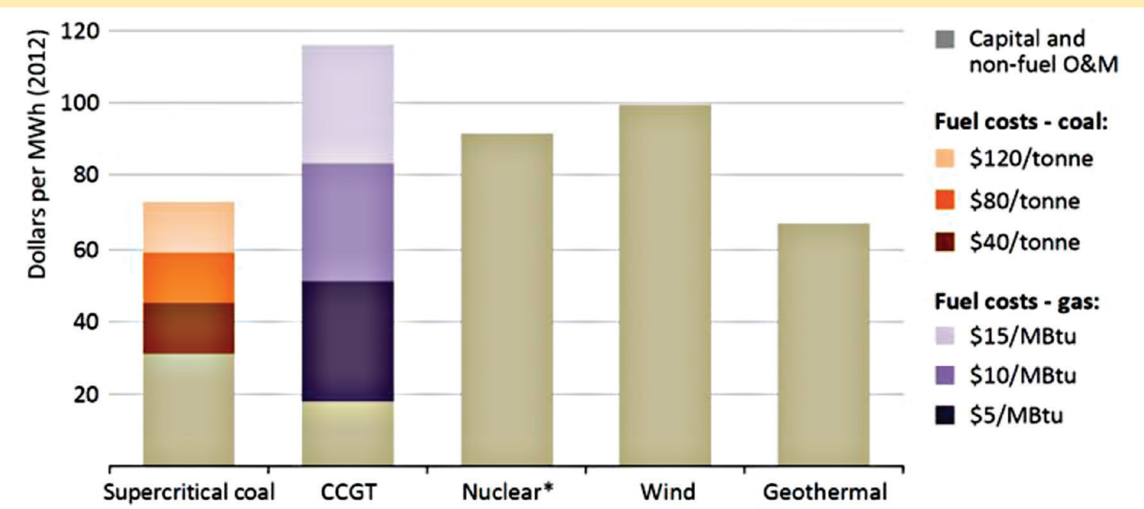
It is important to underline that the financial valuation of benefits has deliberately omitted some of the advantages HVDC technology has over HVAC:

a. HVDC power transmission between networks can operate either asynchronously or at different frequencies;

b. HVDC technology does not increase the short-circuit ratio of the AC system;

c. HVDC lines have a better lightning performance than AC.

FIGURE 86: ELECTRICITY GENERATION COSTS IN SOUTH-EAST ASIA UNDER DIFFERENT COAL AND GAS PRICE ASSUMPTIONS, 2020-2035



* Includes fuel costs, which are a small share of the total. Notes: Assumed capital costs, non-fuel operating and maintenance (O&M) costs, thermal efficiency and construction lead times by technology are in Table 2.3. The assumed economic lifetimes of plants – the period over which the initial investment is recovered – are assumed to be 30 years for coal; 25 years for CCGTs; 35 years for nuclear; 20 years for wind; and 25 years for geothermal. The weighted average cost of capital is assumed to be 8%. No CO_2 price is assumed.

Source: IEA, 2013, (2)

E.4.7 Fault Locator System (FLS)

This initiative can contribute to a reduction in the time and cost of asset maintenance. In particular, as stated in the technical analysis report, the installation of a fault locator system can reduce the time taken by maintenance crews to attend the site of an outage and reduce the actual outage duration by 25%.

Whilst the reduction in the time taken to attend the fault location by maintenance crews is a highly desirable outcome, the fact is that it is negligible compared to the related outage duration and consequent ENS cost. In order to calculate a financial value for this benefit in terms of "**Reduction of energy not served**" it has been assumed that:

a. The total number of these fault events amount to about 10% brownout of the peak load per year and lasts for a duration of 30 minutes;

b. The prevention capacity of this solution is directly proportional to the number of lines equipped with FLS devices. The greater the percentage of lines protected the greater the prevention capacity;

c. The percentage of fault time reduction achievable with FLS is estimated at 25%.

At the time of writing it is known that the Vietnamese network experiences an entirely non-trivial number of faults each lasting for a significant amount of time[5]. The total number of interruptions is about 28 per customer, each with an average duration of 2 hours and 40 minutes. The total number of minutes that an average Vietnamese customer experiences power outages is 4,461 minutes per year, equivalent to 74 hours. The average number of outage events in Vietnam is some 14 times greater than in Europe and America and the accumulated duration nearly 40 times greater.

Table 27 below shows the comparative numbers for outage events and duration from developed economies around the world.

As discovered earlier with voltage collapse events, even if an outage event lasts an average of 30 minutes it can involve large areas of the transmission network (i.e. 10% brownout of the peak load per year). The reduction of fault time is a typical benefit achievable with such FLS devices. Further, based on the fact that such devices can save hours of time [21] to pinpoint the precise fault location, it is reasonable to estimate a 25% reduction in the time taken.

E.4.8 On-line Dissolved Gas-in-oil Analysis (DGA)

According to a study performed by "The Hartford Steam Boiler Inspection and Insurance Company" in the USA the average cost of a transformer fault (and that's only for property damage) is approximately $9,000 per MVA and the fault probability is 0.6% [22].

It has been assumed that:

a. The a DGA device installed in a transformer can prevent 80% of its faults (based on industry standard diagnostics techniques [23]);

b. All new transformers installed in Vietnam will be provided with such monitoring devices; and

c. From 2015 to 2030 the capacity of transformers 500/220kV will increase from 53,251 MVA to 261,303 MVA.

The installation of a DGA in a transformer will result in "**Avoided CAPEX**" reduction of 80%.

TABLE 27: WORLDWIDE DEVELOPED ECONOMIES SAIDI AND SAIFI VALUES

Country	SAIDI (minutes)	SAIFI
USA	244	1.49
Austria	72	0.9
Denmark	24	0.5
France	62	1.0
Germany	23	0.5
Italy	58	2.2
Netherlands	33	0.3
Spain	104	2.2
UK	90	0.8

Source: University of Cambridge, 2012, (3)

E.4.9 Dynamic Thermal Circuit Rating (DTCR)

As stated in the technical analysis report, a good approach to verify the financial benefits of DTCR technologies to the transmission owner is to calculate the cost savings that DTCR systems unlock thus precluding the immediate need for more extensive capital investments. Figure 87 compares different approaches for increasing ratings ranging from line rebuilds, reconductorings to DLR installations.

It is worth noting that the installation of DLR systems is often only a fraction of the cost of other solutions though they do offer lower capacities than other transmission upgrades.

In those cases where the "ampacity" increase allowed by DLR is sufficient for system operational purposes it is possible to estimate benefits in term of "**Avoided CAPEX and Deferred Capacity Investments**". Using DLR makes it possible to avoid or postpone line rebuild/reconductoring, thus avoiding or deferring this type of investment. In particular, in a fast growing electrical system like Vietnamese one, it may happen that the overloading of some lines is only temporarily as the building of new assets (lines, power plants, etc.) can change the location of the most overloaded lines. Therefore, the rebuild/reconductoring of the line could be completely useless and the use of DLR is recommended.

To estimate benefits in terms of "**Avoided CAPEX and Deferred Capacity Investments**" it has been assumed that:

a. Four critical lines have been selected to be equipped with DLR sensors;

b. The length of these lines is approximately 100km;

c. For all of these lines are considered both the cost of DLR solution (1 sensor every 10km) and of reconductoring; and

d. The cost of each DLR sensor is $32,000 while the reconductoring cost is $200,000/km.

Dynamic Thermal Circuit Rating can also contribute 0.45% to the reduction in the OPEX for the transmission system. This represents a saving of $1,600,000 based on NPT's figure of $400,000,000 OPEX for the transmission system. The increased loading limit supported by the DLR application also contributes to reduce the daily operational costs. These estimations are based on the DLR project implemented in Italy by Terna.

E.4.10 Geographic Information Systems (GIS)

The main benefit of the GIS application is the "Direct Transmission OPEX reduction". If the GIS application is developed exclusively for the SAS initiative, the benefit

FIGURE 87: ALTERNATIVE SOLUTIONS COMPARISON TO INCREASE LINE "AMPACITY"

Line Type	Alternative Description	New Rating (% Static)	Cost per Mile
138 kV Lattice, Wood H-Frame	Reconductor Aluminum Conductor Composite Core (ACCC) cable	193%	$321,851
	DLR	110%	$56,200
138 kV Wood H-Frame	Rerate 125 °C Modify structures	130%	$10,561
	Rerate 125 °C Replace structures	130%	$6,919
	Rebuild	209%	$750,000
	DLR	110%	$29,471
138 kV Wood H-frame	Rebuild	140%	$237,871
	DLR	110%	$16,767
138 kV Wood H-Frame	Reconductor	212%	$750,000
	DLR	110%	$28,323
345 kV Lattice Tower	Raise structure heights	120%	$73,600
	DLR	110%	$26,626

Source: U.S. Department of Energy, 2014, (4)

will result in a 10% reduction of the total OPEX of the SAS project. As with FLS, this estimation is based on the elapsed time that is saved in locating faults or problems, especially with remotely controlled equipment as in the case of SAS.

E.4.11 Power quality monitoring and Metering Data Acquisition Systems

In order to assign a financial value to "Power quality monitoring and Metering Data Acquisition Systems" the most important functionality to consider is the "Fault reduction" delivered by the Power quality monitoring system development. In fact, considering the "**Reduction of energy not served**" benefit of this Smart Grind initiative, all the other benefits are negligible or too variable (e.g. "Direct Transmission OPEX reduction" achievable thanks to the development of an electricity market) to be assigned a financial value.

As stated in the technical analysis report, the power quality monitoring development can reduce voltage dips. These events in some cases can cause outages that entail an amount of ENS.

Thus, to estimate benefits in terms of "**Reduction of energy not served**" it has been assumed that:

a. The total amount of the faults events caused by critical voltage dips are equivalent to a 1% brownout of the peak load per year amounting to a total elapsed time of 15 minutes;

b. The prevention capacity of PQ Monitoring is directly proportional to the number of monitoring devices installed on the power transmission network. The greater the number of devices installed, the better the prevention and the greater the cost savings;

c. Power Quality monitoring can reduce fault times by 20%.

Voltages dips are typical phenomena on an electricity transmission network plagued by voltage stability issues. Such events are less critical than voltage collapses both in terms of duration and in terms of the size of the affected area. For this reason the equivalent event duration has been reduced to 15 minutes and the equivalent brownout of the peak load per year has been decreased to 1%. Nevertheless voltage dips have to be considered as a serious issue given the current and predicted industrial development in Vietnam. Such phenomena can and do cause significant damage to industrial plant in factories, especially ones manufacturing high value products.

Power quality monitoring and Metering Data Acquisition Systems can also contribute 5% to the global reduction of OPEX for the transmission system (as part of the 8% reduction discussed in paragraph 'E.3'). According to information received from NPT the transmission system OPEX is equal to $400,000,000 and a 5% reduction is equal to $1,600,000.

The reductions in OPEX costs and fault times are benefits conferred by these two Smart Grid applications and the estimations of the percentage amounts are based on the consultant's experience of developing the Italian Power Quality system in partnership with TERNA (Italian TSO).

E.5 Assumptions about System Level Benefits

At a system level the benefits conferred by the Smart Grid initiatives, as discussed in paragraph 'D.2', include ease of integration of renewable energy sources and thus a reduced need for additional fossil fuel-based power capacity.

While Smart Grid solutions will specifically enable the integration of distributed renewable sources in the transmission network they will also support a more efficient and balanced use of the whole energy generation capacity.

These benefits are not related to a particular Smart Grid initiative but are the cumulative effect of the synergies between many of the Smart Grids technologies deployed in the transmission network. While direct benefits in the preceding section were calculated for each Smart Grid application, this section looks at assigning a value to the system level benefits conferred by the deployment of Smart Grids technologies.

In order to be conservative and not overstate the case for Smart Grid technologies, the value assigned to the system level benefits have not been factored into either the indicators or the economic evaluation of each Smart Grid initiative. However, such benefits have been quantified and assigned a financial value for the whole Smart Grid roadmap implementation. This global evaluation highlights how the investments in developing a certain number of Smart Grid solutions will benefit the performance, management and operational cost reduction of the power system in Vietnam,

According to the Power Development Master Plan, Vietnam's purpose is to prioritize the development of renewable energy sources for electricity generation, increasing the percentage of electricity produced by these energy sources from 3.5% of total electricity production in 2010 to 4.5% in 2020 and 6.0% in 2030. In particular, the aim is to bring the total wind power capacity from the current negligible levels to around 1,000 MW by 2020 and about 6,200 MW by 2030. The aim is to increase the proportion of electricity production from wind power from 0.7% in 2020 to 2.4% by 2030.

Linked to the development of renewable energy sources (in particular wind power capacity) the system level benefits can be split into the three categories as proposed in paragraph 'D.2'.

E.5.1 Optimized energy generation mix

The replacement of conventional power plants with wind generation (as well as other alternative energies) to supply an ever-growing demand entails different investment strategies for the construction and operations of new power plants. The leveled cost of energy ("LCOE") is a possible mechanism for estimating the size of the investment required.

LCOE is often cited as a convenient summary yardstick of the overall competiveness of different generating technologies. It represents the energy cost of building and operating a generating plant over an assumed life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs and an assumed utilization rate for each plant type.

In order to assign a financial value for the annual benefits related to the optimization of the generation mix it is preferable to start from a forecast of the LCOE values over at least two time periods (mid-term and long-term) because this parameter can change significantly over time for some generating technologies.

A credible international source like the U.S. Energy Information Administration (EIA) was considered as a source to capture the variability of the stabilized cost of new generation resources predicted in 2019 (Figure 88) and 2040 (Figure 89). These forecasted figures are available from the annual energy outlook 2014.

Considering the current energy mix of Vietnam's power generation profile, the gas-fired power plants and conventional fossil-fuel plants are considered candidates for replacement with wind generation because of their predicted costs. The benefits of wind generation would still be a net positive if an LCOE of $ 100/MWh is considered because Vietnam

FIGURE 88: STABILIZED COST OF ELECTRICITY (LCOE) FOR NEW GENERATION RESOURCES, 2019

	Range for Total System LCOE (2012 $/MWh)		
Plant Type	Minimum	Average	Maximum
Dispatchable Technologies			
Conventional Coal	87.0	95.6	114.4
IGCC	106.4	115.9	131.5
IGCC with CCS	137.3	147.4	163.3
Natural Gas-fired			
Conventional Combined Cycle	61.1	66.3	75.8
Advanced Combined Cycle	59.6	64.4	73.6
Advanced CC with CCS	85.5	91.3	105.0
Conventional Combustion Turbine	106.0	128.4	149.4
Advanced Combustion Turbine	96.9	103.8	119.8
Advanced Nuclear	92.6	96.1	102.0
Geothermal	46.2	47.9	50.3
Biomass	92.3	102.6	122.9
Non-Dispatchable Technologies			
Wind	71.3	80.3	90.3
Wind – Offshore	168.7	204.1	271.0
Solar PV[2]	101.4	130.0	200.9
Solar Thermal	176.8	243.1	388.0
Hydroelectric[3]	61.6	84.5	137.7

Source: Energy Information Administration, 2014, (5)

FIGURE 89: LEVELIZED COST OF ELECTRICITY (LCOE) FOR NEW GENERATION RESOURCES, 2040

	Range for Total System LCOE (2012 $/MWh)		
Plant Type	Minimum	Average	Maximum
Dispatchable Technologies			
Conventional Coal	87.0	95.6	114.4
IGCC	106.4	115.9	131.5
IGCC with CCS	137.3	147.4	163.3
Natural Gas-fired			
Conventional Combined Cycle	61.1	66.3	75.8
Advanced Combined Cycle	59.6	64.4	73.6
Advanced CC with CCS	85.5	91.3	105.0
Conventional Combustion Turbine	106.0	128.4	149.4
Advanced Combustion Turbine	96.9	103.8	119.8
Advanced Nuclear	92.6	96.1	102.0
Geothermal	46.2	47.9	50.3
Biomass	92.3	102.6	122.9
Non-Dispatchable Technologies			
Wind	71.3	80.3	90.3
Wind – Offshore	168.7	204.1	271.0
Solar PV[2]	101.4	130.0	200.9
Solar Thermal	176.8	243.1	388.0
Hydroelectric[3]	61.6	84.5	137.7

Source: Energy Information Administration, 2014, (5) will likely require gas to be imported at higher costs than reported by EIA.

The LCOE of conventional generation systems has been estimated using a conservative approach. In fact the average LCOE of the combined cycle and the conventional coal power plant has been assumed in order to quantify the total reduction of the generation costs achievable with the implementation of new wind capacity in the Vietnamese network. This calculation has been performed for each year of the time horizon starting from the wind penetration timeline assumption shared with Vietnamese stakeholders. The total nominal reduction of the generation cost is $873,000,000 at the end of the analyzed period (15th year) as shown in Table 28 and corresponds to $305,000,000 discounted to 2015.

E.5.2 Increased fuel availability

The reduced fuel consumption has been based on the reduced Natural gas power capacity substituted by wind generation and assumes that an average amount of fuel needed to produce one MWh of energy is equal to 7.03 MBTU (typical average value of new combined cycle and new open cycle gas turbine).

Table 29 shows the annual reduction of fuel consumption based on the wind penetration assumptions shared with NPT/NLDC. This benefit has already been monetized in the estimated reduction of generation cost, as it is included in the calculation of the LCOE parameter. Nevertheless it is an important factor for the evaluation of the impact of new renewable generation and for the energy strategy of Vietnam.

E.5.3 Reduced GHG emissions

The reduced Natural gas power requirement caused by using wind generation instead determines the reduction of GHG emissions. For this calculation the average CO2 emission of 0.416 ton/MWh for gas-fired generation is assumed (typical average value of new combined cycle and new open cycle gas turbine).

In order to assess the financial value of this benefit a conservative value of 10$/ton for CO2 emission has been assumed.

Table 30 shows the annual financial value of CO2 emission savings, which determines a total nominal benefit equal to $346,000,000 in the analyzed period and corresponds to $128,000,000 discounted to 2015.

TABLE 28: REDUCTION OF ENERGY GENERATION COST DUE TO THE INTEGRATION OF WIND GENERATION ENABLED BY THE SMART GRID ROADMAP

Year	Wind Capacity installed [MW]	Wind energy generation [TWh] (a)	Average LCOE Gas-fired Power Plants [$/MWh] (b)	LCOE Wind [$/MWh] (c)	LCOE difference [$/MWh] (d=b-c)	Yearly generation cost reduction [M$] (a·d)
2015	0	0	80.8	80.3	0.5	0
2016	200	0.4	80.8	80.3	0.5	0
2017	400	0.8	80.8	80.3	0.5	0
2018	600	1.2	80.8	80.3	0.5	1
2019	800	1.6	80.8	80.3	0.5	1
2020	1,000	2	84.1	73.1	11	22
2021	1,520	3.04	84.1	73.1	11	33
2022	2,040	4.08	84.1	73.1	11	45
2023	2,560	5.12	84.1	73.1	11	56
2024	3,080	6.16	84.1	73.1	11	68
2025	3,600	7.2	84.1	73.1	11	79
2026	4,120	8.24	84.1	73.1	11	91
2027	4,640	9.28	84.1	73.1	11	102
2028	5,160	10.32	84.1	73.1	11	114
2029	5,680	11.36	84.1	73.1	11	125
2030	6,200	12.4	84.1	73.1	11	136
					TOTAL Generation cost reduction [M$]:	873

Source: Authors

TABLE 29: REDUCTION FUEL CONSUMPTION DUE TO THE INTEGRATION OF WIND GENERATION ENABLED BY THE SMART GRID ROADMAP

Year	Wind Capacity installed [MW]	Wind energy generation [TWh] (a)	Average fuel consumption of gas-fired generation [MBTU/MWh] (b)	Average fuel consumption of gas-fired generation [106 MBTU] (c=a·b)
2015	0	0.0	7.03	0.0
2016	200	0.4	7.03	2.8
2017	400	0.8	7.03	5.6
2018	600	1.2	7.03	8.4
2019	800	1.6	7.03	11.2
2020	1,000	2.0	7.03	14.1
2021	1,520	3.0	7.03	21.4
2022	2,040	4.1	7.03	28.7
2023	2,560	5.1	7.03	36.0
2024	3,080	6.2	7.03	43.3
2025	3,600	7.2	7.03	50.6
2026	4,120	8.2	7.03	57.9
2027	4,640	9.3	7.03	65.2
2028	5,160	10.3	7.03	72.5
2029	5,680	11.4	7.03	79.9
2030	6,200	12.4	7.03	87.2
			TOTAL fuel savings [106 MBTU]:	585

Source: Authors

TABLE 30: REDUCTION GHG DUE TO THE INTEGRATION OF WIND GENERATION ENABLED BY THE SMART GRID ROADMAP

Year	Wind Capacity installed [MW]	Wind energy generation [TWh] (a)	Average CO2 emission rate of gas-fired generation [tons/MWh] (b)	Average CO2 emission of gas-fired generation [Mtons] (c=a·b)	CO2 emission monetization [$/ton] (d)	CO2 emission savings [M$] (c·d)
2015	0	0.0	0.416	0.0	10.0	0.0
2016	200	0.4	0.416	0.2	10.0	1.7
2017	400	0.8	0.416	0.3	10.0	3.3
2018	600	1.2	0.416	0.5	10.0	5.0
2019	800	1.6	0.416	0.7	10.0	6.7
2020	1,000	2.0	0.416	0.8	10.0	8.3
2021	1,520	3.0	0.416	1.3	10.0	12.6
2022	2,040	4.1	0.416	1.7	10.0	17.0
2023	2,560	5.1	0.416	2.1	10.0	21.3
2024	3,080	6.2	0.416	2.6	10.0	25.6
2025	3,600	7.2	0.416	3.0	10.0	30.0
2026	4,120	8.2	0.416	3.4	10.0	34.3
2027	4,640	9.3	0.416	3.9	10.0	38.6
2028	5,160	10.3	0.416	4.3	10.0	42.9
2029	5,680	11.4	0.416	4.7	10.0	47.3
2030	6,200	12.4	0.416	5.2	10.0	51.6
					TOTAL CO2 emission savings [M$]:	346

Source: Authors

E.6 Integration of Renewable energy generation

International experience demonstrates that an inadequate network infrastructure is a significant barrier to efficient utilization of available production from variable renewable energy and as a consequence can be an obstacle to the investments in new RES generation.

Smart Grid solutions can facilitate the integration of RES whilst limiting the need for additional infrastructure and improving system operations. Table 31 shows the benefits obtained by implementing each project and lists them in order of merit in terms of their potential for enabling RES generation.

The HVDC technology and the Dynamic Thermal Circuit Rating are perhaps the most versatile of the Smart Grid initiatives in terms of integrating new variable renewable generation. In fact the increased transfer capacity is a fundamental benefit, which will facilitate the installation of wind or solar power plants carrying the generated energy to the load areas. HVDC can also balance the natural fluctuation of renewables thanks to the active power control, which is an inherent advantage for supporting variable generation.

WAMS can be an important enabling technology for a large-scale variable RES installation thanks to the real-time monitoring and analysis, which precludes potential stability problems. As renewable penetration increases, power systems will be more responsive when dealing with sudden changes and the potential stability issues.

Another benefit to be considered in this assessment is the ability to avoid having to curtail RES generation. Just as WAMS, SAS, SVC, LLS, PQ and FLS can help with "the reduction of energy not served", they could also eliminate the need to reduce renewable energy that cannot be generated for want of the system's ability to manage the additional load.

DGA and GIS do not have a significant impact on RES investment decisions.

E.7 Assumptions on blackout prevention

The information collected during the discovery process reveals that Vietnamese customers suffer a number of power outages, each of a considerable average duration [20]. Amortizing the numbers across the population gives a total of 28 interruptions per customer, per year, with each one lasting 2 hours and 40 minutes. The total elapsed time that an average customer suffers a power outage in Vietnam is 4,461 minutes per year, or 74

TABLE 31: EFFECTS OF THE SMART GRID APPLICATIONS ON RENEWABLE GENERATION INTEGRATION

MERIT ORDER	SMART GRID APPLICATION	EFFECTS ON RENEWABLE GENERATION INTEGRATION
1	HVDC	Increased transfer capacity Active power control
2	DTCR	Increased transfer capacity
3	SVC	Stability issues avoided Reduced RES curtailment
	WAMS	Stability issues avoided Reduced RES curtailment
4	SAS	Reduced RES curtailment
	LLS	Reduced RES curtailment
	PQ & Metering	Reduced RES curtailment
	FLS	Reduced RES curtailment
5	DGA	Negligible
	GIS	Negligible

Source: Authors

hours. Comparing these figures with mature economies highlights that the average Vietnamese customer experiences 14 times more interruptions than a European customer and for nearly 40 times as long.

This data and the information collected during the discovery process reveals that brownouts (or partial blackouts) are a very serious problem in Vietnam [24] and such events hit firms hard reducing their ability to attract investments [4] [25]. For business users these interruptions amount to 10% of the Peak Demand for 30 minutes a year, which is pretty conservative given the average private Vietnamese citizen's experience.

Nevertheless, the prevention of the frequency of major events like blackouts has not been introduced in the economic indicators or in the evaluation.

During May 2013 the southern region of Vietnam experienced a massive power outage that lasted for some hours. This was caused by a truck that, while delivering a tree, damaged a line in the national power grid (500 KV) in New Bình Du'o'ng City urban area. The transmission system was not compliant with the N-1 security criterion, so the truck incident led to a cascade effect causing a wide ranging blackout across twenty two provinces. This is a typical case where a small incident has a major knock-on effect causing significant damage.

Blackout prevention is achievable with the deployment of Smart Grid technology [26] [27] [28]. In fact blackout prevention was one the main drivers that pushed the development of Smart Grids technologies in USA, Europe and around the world.

The Guidebook of the Cost/Benefit Analysis of EPRI's Smart Grid Demonstration Projects examines the benefits and costs of avoiding major power interruption [29].

The fast growth in demand as well as the rapid power network development seems to be affecting the South of Vietnam far more than the north, in fact to the extent of 49% of the total load [12] with an average duration of 3 hours.

The main reason for introducing the Smart Grid technologies is to reduce the frequency of these major events which are causing huge economic losses and affecting the credibility of the network operators and impacting the country's potential for attracting investments.

The analysis suggests that Smart Grid technologies can avoid at least one major event such as the one in 2013, which seems to occur every 8 years. Allowing for the time taken to achieve the full rollout of the relevant Smart Grid technology it is likely that over the next 15 years it will be possible to prevent 4 major blackouts. Table 32 shows the total interruption cost reduction due to blackouts prevented, which the Smart Grid technology will make possible. This is a reasonable assumption given that, according to ENV [30], there were 18 Power System Collapses that occurred between 1995 and 2006. There were also several others brownout events in the following 7 years (including the 2013 blackout). These outages occurred 8 times in the Northern Power System and 9 times in the Southern Power System. The Northern and the Southern power generation systems contribute 41% and 49% respectively to the total load. The potential total cost reduction of reduced or prevented outages is estimated at $644,000,000, which corresponds to a discounted value of $275,000,000 for 2015.

The benefit calculated above by avoiding 4 major events is quite conservative considering that the cost of a single blackout has an estimated value in the billions. This reduction/prevention together with the system level benefits will make a significant difference to the economic indicators.

The different Smart Grid solutions together provide the means of reducing or entirely preventing outages. Table 33 shows the contribution from each project and prioritizes them according to the level of impact they will have on blackout mitigation/prevention.

TABLE 32: REDUCTION OF INTERRUPTION COST DUE TO BLACKOUT REDUCTION ENABLED BY THE SMART GRID SOLUTIONS

Year	ENS [MW]	Interruption cost [M$]	Yearly interruption cost reduction [M$]
2017	40,021	83	83
2021	58,594	122	122
2025	85,788	178	178
2029	125,602	261	261
		TOTAL interruption cost reduction due to avoided blackouts [M$]:	644

Source: Authors

TABLE 33: EFFECTS OF THE SMART GRID APPLICATIONS ON BLACKOUT PREVENTION

MERIT ORDER	SMART GRID APPLICATION	CONTRIBUTION FOR BLACKOUT PREVENTION
1	WAMS HVDC SVC	Increased network stability
2	DTCR SAS LLS FLS	Increased efficiency in system operation
3	PQ & Metering DGA GIS	Negligible

Source: Authors

E.8 Summary of the Benefits

The benefits calculated are at the individual level considering each Smart Grid application and provide an overall systemic level view.

The financial valuation of the system level benefits has not been factored into the economic indicators in the interests of taking a conservative view. This deliberate underestimation has also been extended to the economic indicators for the individual Smart Grid applications. However, they have been quantified for the whole Smart Grid roadmap implementation.

A summary of all the benefits calculated is presented in Table 34 and in Figure 90.

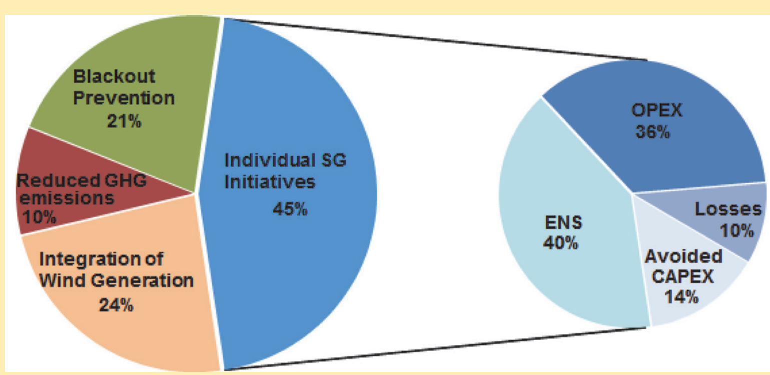
The system evaluation highlights how the investments in developing a certain number of Smart Grid solutions (viable for Vietnam) allow building a "Smart" transmission network and enhancing electrical system reliability.

TABLE 34: SUMMARY OF THE BENEFITS

Benefit	Discounted Benefit Value (2015 $)	Comment
Individual SG Initiatives	$586,217,918	Factored in to calculations for the economic indicators
Integration of Wind Generation and Increased Fuel Availability	$305,000,000	Not factored in to calculations for the economic indicators
Reduced GHG emissions	$128,000,000	
Blackout Prevention	$275,000,000	

Source: Authors

FIGURE 90: SUMMARY OF THE BENEFITS



Source: Authors

F. Identify and Quantify Costs

F.1 Key Points Summary

This chapter describes all the assumptions related to the costs necessary for the implementation of the Smart Grid solutions.

The costs are reported in terms of capital expenditures (CAPEX) and operating expenditures needed to operate the systems (OPEX). The nominal and discounted values of such costs amortized over the time horizon are summarized in Table 35.

F.2 Substation Automation System (SAS)

Investment cost for the implementation of the SAS in existing substation (Table 36) is included in the NPT presentation: "Key efficiency and reliability challenges for NPT and current Smart Grid modernization opportunities and priorities". In the presentation two different costs are considered for retrofitting 500 kV substations and 220 kV substations.

TABLE 35: SUMMARY OF COSTS OF SMART GRID INITIATIVES

Initiative	Nominal Costs	Discounted Costs	Scale of operation
SAS	CAPEX: $226,200,000 OPEX: $25,205,250	CAPEX: $147,903,537 OPEX: $10,854,340	18 retrofitted substations 150 new SAS
WAMS	CAPEX: $1,792,000 OPEX: $214,840	CAPEX: $1,268,311 OPEX: $96,615	224 PMUs installed at 500 kV and 220 kV voltage level
Lightning Location System	CAPEX: $1,668,000 OPEX: $899,000	CAPEX: $1,431,404 OPEX: $443,395	20 detectors monitoring lightning activity across Vietnam
SVC	CAPEX: $31,500,000 OPEX: $1,255,500	CAPEX: $24,962,690 OPEX: $588,058	900 Mvar SVCs installed in the most critical area of Vietnam in terms of voltage control
HVDC	CAPEX: ($16,800,000) OPEX: $118,098,000	CAPEX: ($13,313,434) OPEX: $55,315,436	2,000 MW interconnection, 800 km length, using DC instead of AC technology
FLS	CAPEX: $8,400,000 OPEX: Negligible	CAPEX: $7,289,256 OPEX: Negligible	140 Fault locators
DGA	CAPEX: $77,592,000 OPEX: $3,343,245	CAPEX: $41,696,690 OPEX: $1,364,572	732 transformers equipped, (all existing and new)
Dynamic Thermal Circuit Rating	CAPEX: $1 280 000 OPEX: $371 200	CAPEX: $1,110,743 OPEX: $183,079	40 sensors monitoring 400 km lines
GIS	CAPEX: $175,000 OPEX: $262,500	CAPEX: $159,090 OPEX: $133,106	Geographic information of power system components across Vietnam
Power quality monitoring and Metering Data Acquisition Systems	CAPEX: $301,500 OPEX: $97,214	CAPEX: $241,648 OPEX: $45,962	105 power quality measurement devices at 500 kV and 220 kV voltage level

Source: Authors

TABLE 36: CAPEX OF SUBSTATION AUTOMATION SYSTEM ADOPTED IN THE BUSINESS CASE

		Quantity over time horizon (a)	Cost per unit [$] (b)	Total cost [$] (a·b)	Source
CAPEX	500 kV substations retrofitting	5	2,400,000	12,000,000	NPT
	220 kV substations retrofitting	13	900,000	11,700,000	NPT
	500 kV new substations	45	2,400,000	108,000,000	NPT
	220 kV new substations	105	900,000	94,500,000	NPT

Source: Authors

TABLE 37: OPEX OF SUBSTATION AUTOMATION SYSTEM ADOPTED IN THE BUSINESS CASE

		Total Yearly Cost [$]	Source
OPEX	500 kV substations retrofitting	24,000	CESI
	220 kV substations retrofitting	9,000	CESI
	500 kV new substations	24,000	CESI
	220 kV new substations	9,000	CESI

Source: Authors

In the Business Case the cost for the implementation of SAS equipment in new substations has been assumed to be the same as the retrofitting an existing substation[6].

It is assumed that all new substations installed from 2016 will be equipped with SAS. The NPT forecast indicates the number of new substations.

OPEX estimates in Table 37 are based on 1% of capital expenditure and correspond to the full implementation of the SAS in existing and planned substations.

F.3 Wide Area Monitoring System (WAMS)

The cost of a single Phase Measurement Unit (PMU) has been provided by NPT.

In the business case it has been assumed that PMUs will be installed in all the existing and planned substations for both the 500 kV and 220 kV networks (Table 38).

TABLE 38: CAPEX OF WIDE AREA MONITORING SYSTEM ADOPTED IN THE BUSINESS CASE

		Quantity over time horizon (a)	Cost per unit [$] (b)	Total cost [$] (a·b)	Source
CAPEX	PMU installation 500 and 220 kV existing substations	74	8,000[a]	592,000	Cost per unit source: NPT, Quantity assumption: CESI
	PMU installation 500 and 220 kV new substations	150	8,000	1,200,000	Cost per unit source: NPT, Quantity assumption: CESI

Source: Authors

a. The source of the WAMS prices is the Investment Management Department—EVN NPT—and is related to already installed PMU cost.

TABLE 39: OPEX OF WIDE AREA MONITORING SYSTEM ADOPTED IN THE BUSINESS CASE

		Total Yearly Cost [$]	Source
OPEX	PMU installation 500 and 220 kV existing substations	5,920	CESI
	PMU installation 500 and 220 kV new substations	12,000	CESI

Source: Authors

OPEX estimates in Table 39 are based on 1% of capital expenditures and correspond to the full implementation of the PMUs in existing and planned substations.

F.4 Lightning Location System (LLS)

CAPEX for the Lightning Location System will vary as a function of the number of lightning detectors installed. The number of detectors indicated in Table 40 (approximately 20) is considered the minimum amount needed to provide a reliable and useful lightning monitoring system based on the geography of Vietnam.

It is important to highlight that one of the main characteristics of this Smart Grid initiative is its capability in driving the Transmission Surge Line Arresters (TLSA) installation. The investment in purchasing TLSAs is not considered in this analysis because it has been assumed that NPT has however to install such devices, independently from the development of a Lightning Location System.

Civil works (Table 40) and site rental (Table 41) will vary depending on the installation sites (an average value has been considered).

Data analysis operational cost has been estimated based on 48 man-months per year for the analysis team at an estimated cost of $500/month.

Site rental and electricity supply depend on the number of lightning detectors installed, while other OPEX (Data analysis, hardware and software operations and maintenance) are not included in these calculations.

F.5 Static Var Compensator (SVC)

The Cost per Mvar of Static Var Compensator has been supplied by manufacturers.

Total SVC capacity installed (900 Mvar) has been estimated by CESI based on an estimate of 20% of the total

TABLE 40: CAPEX OF LIGHTNING LOCATION SYSTEM ADOPTED IN THE BUSINESS CASE

		Quantity over time horizon (a)	Cost per unit [$] (b)	Total cost [$] (a·b)	Source
CAPEX	Lightning detectors	20	54,000	1,080,000	CESI
	Civil works	20	10,000	200,000	CESI
	Telecommunication between detectors and control center, data collection and management (ADSL, Routers, DB's)	1	30,000	30,000	CESI
	Lightning Location Central Analyzer software	1	172,000	172,000	CESI
	Archiving and handling of Lightning data software	1	186,000	186,000	CESI/ Service provider

Source: Authors

TABLE 41: OPEX OF LIGHTNING LOCATION SYSTEM ADOPTED IN THE BUSINESS CASE

		Total cost [$] (a·b)	Source
OPEX	Site rental	10,000	CESI
	Electricity supply	4,000	CESI
	Data analysis	24,000	CESI
	Hardware and software operation and maintenance	24,000	CESI

Source: Authors

reactive power regulation capacity. The basis for this estimate is as follows:

a. The SVC capacity in the United Kingdom is 30% of the total reactive power regulation capacity;

b. The installation of Static Var Compensators in Vietnam will be limited to those areas most affected by voltage stability issues. SVC installation will very likely be confined to the central area of Vietnam which is characterized by a lack of generation capacity and long transmission lines carrying the energy generated in the north of the country to the southern region where there is a higher demand.

The cost per Mvar refers to the re-locatable technology, which has higher costs than for fixed units but allows much greater flexibility in the choice of ad hoc locations. Re-locatable SVCs can be moved around to different parts of the grid depending on the dynamic operational requirements of a rapidly changing topology. The average cost of a large sized SVC installation including dedicated transformers and feeders has been in the range of $35,000-$55,000 [31] per Mvar in the past years. The installation of the SVC in the tertiary winding of an existing transformer can reduce this cost by as much as 30%. Furthermore the information collected from manufacturers shows how the cost is shrinking thanks to the economy of scale due to the wider take-up of this relatively new technology.

Given that the SVCs currently installed in Vietnam do not have dedicated transformers, a similar configuration has been assumed for new installs thus a conservative cost of $35,000 for the installation of the Static Var Compensator has been adopted (based on $30,000 per Mvar for the system and $5,000 per Mvar for the civil works).

TABLE 42: CAPEX OF STATIC VAR COMPENSATORS ADOPTED IN THE BUSINESS CASE

		Capacity installed over time horizon [Mvar] (a)	Cost per Mvar [$/Mvar] (b)	Total cost [$] (a·b)	Source
CAPEX	Static Var Compensator (re-locatable)	900	30,000	27,000,000	Capacity installed source: CESI; Cost source: manufacturers
	Civil works	900	5,000	4,500,000	CESI

Source: Authors

TABLE 43: OPEX OF STATIC VAR COMPENSATORS ADOPTED IN THE BUSINESS CASE

		Total Yearly Cost [$]	Source
OPEX	Preventive maintenance (3 days/year) + On-line support	60,000	CESI
	Corrective maintenance	30,000	CESI
	Spares e consumables	3,000	CESI

Source: Authors

F.6 High Voltage Direct Current (HVDC) technology

The incremental cost of a new 800 km DC link as opposed to an AC solution has been estimated in order to assess the economic feasibility of HVDC technology.

The costs (reported in Table 44) have been calculated based on the following hypotheses for the HVDC link:

a. Bipolar +/- 500 kV Overhead line;

b. Rated power: 2,000 MW;

c. Four sub-conductors per pole; and

d. VSC technology for the converter stations.

Other assumptions for the incremental cost calculation are the following:

a. 500 kV and 2,000 MW rated power for both AC solution;

b. AC and HVDC lines have the same length;

c. The sizing of the conductors is optimized separately for AC and HVDC. The sizing of the section is made by an optimization which is aimed to match the investment cost of the line and the cost of losses over 15 years (optimum conductors to minimize investment plus capitalized cost of losses);

d. HVDC transmission lines require 25 meters less right of way than HVAC;

e. The average cost of the right of way is $10 per square meter, which makes HVDC a much more economical option;

f. The additional equipment required for AC transmission (substations, feeders, FACTS) is 10% of the total cost of the lines; and

g. The cost of the lines includes the engineering, procurement and construction costs and the estimations take into account the localizing factor.

It is possible to calculate the total CAPEX of the HVAC and HVDC interconnections from the details in Table 44:

a. HVAC: $692,800,000;

b. HVDC: $676,000,000.

Therefore, the use of HVDC technology determines a CAPEX saving of $16,800,000.

The OPEX shown in Table 45 has been estimated at 1.5% of CAPEX for the HVDC and HVAC transmission lines and 3% of CAPEX for the converter stations.

F.7 Fault Locator System (FLS)

For the Fault Locator System only the cost of the equipment has been considered (Table 46). Other investment and operational costs have been disregarded.

TABLE 44: CAPEX OF HIGH VOLTAGE DIRECT CURRENT TECHNOLOGY ADOPTED IN THE BUSINESS CASE

		Quantity (a)	Cost per unit ([$/km] for the line, [$] for others) (b)	Total cost [$] (a·b)	Source
CAPEX	HVDC Overhead lines engineering, procurement and construction	800 km	345,000	276,000,000	CESI
	HVDC Converter stations	2	200,000,000	400,000,000	Manufacturers
	HVAC Overhead lines engineering, procurement and construction (Avoided CAPEX)	800 km	-560,000	-448,000,000	CESI
	HVAC Cost of additional equipment (Substations, feeders, Facts, ...) (Avoided CAPEX)	1	-44,800,000	-44,800,000	CESI
	HVAC additional right of way cost (Avoided CAPEX)	1	-200,000,000	-200 000,000	CESI

Source: Authors

TABLE 45: OPEX OF HIGH VOLTAGE DIRECT CURRENT TECHNOLOGY ADOPTED IN THE BUSINESS CASE

		Total Yearly Cost [$]	Source
OPEX	HVDC OHL O&M	4,140,000	CESI
	HVDC O&M Converter stations	12,000,000	CESI
	HVAC OHL O&M (Avoided OPEX)	-7,392,000	CESI

Source: Authors

TABLE 46: CAPEX OF FAULT LOCATOR SYSTEM ADOPTED IN THE BUSINESS CASE

		Quantity over time horizon (a)	Cost per unit [$] (b)	Total cost [$] (a·b)	Source
CAPEX	Equipment	140	60,000	8,400,000	NPT

Source: Authors

F.8 On-line Dissolved Gas-in-oil Analysis (DGA)

The Business Case assumes that only transformers installed after 2015 will be equipped with Dissolved Gas-in-oil sensors.

The number of new transformers anticipated over the time horizon has been estimated on the basis of the new transformer capacity forecast by NPT.

NPT forecasts 68,100 MVA new 500 kV transformer capacity and 139,952 MVA new 220 kV transformer capacity in the 2015-2030 period. Assuming 525 MVA as a reference size of the 500 kV transformers and 250 MVA for the 220 kV transformers, the number of sensors is estimated at 690. All the existing 500 kV transformers are assumed to be equipped with the sensors i.e. a total of 42 sensors. The CAPEX evaluation is shown in Table 47.

The OPEX costs shown in Table 48 are estimated at 0.5% of capital expenditures for every year.

TABLE 47: CAPEX OF ON-LINE DISSOLVED GAS-IN-OIL ANALYSIS ADOPTED IN THE BUSINESS CASE

		Quantity over time horizon (a)	Cost per unit [$] (b)	Total cost [$] (a·b)	Source
CAPEX	Sensors on existing transformers	42	106,000	4,452,000	Cost per unit source: NPT, Quantity assumption: CESI (elaboration on NPT documentation)
	Sensors on new transformers	690	106,000	73,140,000	Cost per unit source: NPT, Quantity assumption: CESI (elaboration on NPT documentation)

Source: Authors

TABLE 48: OPEX OF ON-LINE DISSOLVED GAS-IN-OIL ANALYSIS ADOPTED IN THE BUSINESS CASE

		Total Yearly Cost [$]	Source
OPEX	O&M DGA new transformers	373,650	CESI

Source: Authors

TABLE 49: CAPEX OF DYNAMIC THERMAL CIRCUIT RATING ADOPTED IN THE BUSINESS CASE

		Quantity over time horizon (a)	Cost per unit [$] (b)	Total cost [$] (a·b)	Source
CAPEX	Sensors	40	32,000	1,280,000	Cost per unit source: manufacturer, Quantity assumption: CESI

Source: Authors

TABLE 50: OPEX OF DYNAMIC THERMAL CIRCUIT RATING ADOPTED IN THE BUSINESS CASE

		Total Yearly Cost [$]	Source
OPEX	O&M DTCR	25,600	CESI

Source: Authors

F.9 Dynamic Thermal Circuit Rating (DTCR)

The number of sensors to be deployed has been estimated at one sensor every 10 km of line length. In the business case four lines of 100 km length are equipped with sensors, therefore the total amount of sensors required is 40 (see Table 49).

OPEX reported in Table 50 have been calculated considering 2% of CAPEX for every year.

F.10 Geographic Information Systems (GIS)

GIS costs are mainly related to the development of the software and user interfaces, which will facilitate better operational control and management of network automation. Table 51 shows the costs assumed for the technology and includes hardware.

The OPEX costs shown in Table 52 are estimated at 10% of CAPEX for every year.

TABLE 51: CAPEX OF GEOGRAPHIC INFORMATION SYSTEM ADOPTED IN THE BUSINESS CASE

		Quantity over time horizon (a)	Cost per unit [$] (b)	Total cost [$] (a·b)	Source
CAPEX	Software applications	1	150,000	150,000	CESI
	Hardware equipment	1	25,000	25,000	CESI

Source: Authors

TABLE 52: OPEX OF GEOGRAPHIC INFORMATION SYSTEM ADOPTED IN THE BUSINESS CASE

		Total Yearly Cost [$]	Source
OPEX	Hardware and software maintenance	17,500	CESI

Source: Authors

F.11 Power Quality monitoring and Metering Data Acquisition Systems

It has been assumed that thirty percent of the substations will be equipped with power quality analyzers in order to facilitate complete and effective monitoring. The number reported in Table 53 (105 analyzers) refers to the total installed over the time horizon. In fact the installation of the devices is aligned with the installation of new substations.

The equipment installed in order to carry out Power Quality monitoring can also be used by the Metering and Data Acquisition system.

Data analysis is based on an estimated 3 man-months per year for the analysis team at a cost of 500 $/month (Table 54).

TABLE 53: CAPEX OF POWER QUALITY MONITORING AND METERING DATA ACQUISITION SYSTEMS ADOPTED IN THE BUSINESS CASE

		Quantity over time horizon (a)	Cost per unit [$] (b)	Total cost [$] (a·b)	Source
CAPEX	Equipment	105	2,300	241,500	Cost per unit source: manufacturer, Quantity assumption: CESI
	Software license and hardware in the control center	1	60,000	60,000	Cost per unit source: manufacturer/provider, Quantity assumption: CESI

Source: Authors

TABLE 54: OPEX OF POWER QUALITY MONITORING AND METERING DATA ACQUISITION SYSTEMS ADOPTED IN THE BUSINESS CASE

		Total Yearly Cost [$]	Source
OPEX	O&M control center + software updates	6,000	Manufacturer/provider
	Data analysis	1,500	CESI

Source: Authors

G. Compare Costs and Benefits

G.1 Key Points Summary

This chapter aims to compare costs and benefits for all the Smart Grid solutions in order to get a reliable estimation of their economic KPIs.

It is important to stress that these values and indicators are very conservative. This is because the system level discounted benefits derived from the optimized energy mix and increased fuel availability ($305,000,000), reduced GHG emission ($128,000,000) as well as the prevention of major blackout events ($275,000,000) were not internalized in the economic indicators (NPV, EIRR and B/C ration). This deliberate underestimation makes the case for the Smart Grid technologies all the more compelling.

A table is presented in the following paragraphs for each Smart Grid initiative. In the top part it reports four parameters which are the synthetic values (KPIs) of the direct financial benefits of the project:

a. **Total NPV 2030**: The Net Present Value represents the discounted cash flows, i.e. the present value of future (up to 2030) cash flows;

b. **EIRR**: The Economic Internal Rate of Return on an investment or project is the "annualized effective compounded return rate" (or rate of return) that makes the Net Present Value of all cash flows (both positive and negative) of a particular investment equal to zero;

c. **B/C ratio**: The Benefits-Costs ratio summarizes the overall value for money of a project and it is calculated as the ratio of the discounted present values of benefits and the discounted present values of costs;

d. **Switching value**: This is the value that an estimated benefit must achieve in order to equal zero NPV. The assumption is chosen specifically for each Smart Grid initiative considering both the uncertainty of its estimation and the impact on the economic benefits of the project. It is important to underline that the Transmission OPEX reduction benefit, if present, is considered equal to zero in the breakeven calculation (conservative approach).

The lower part of the table is where the benefits and costs (identified respectively in chapters 'E' and 'F') are detailed.

Table 55 summarizes the synthetic values of the economic benefits of each Smart Grid initiative.

TABLE 55: SUMMARY OF THE SYNTHETIC VALUES OF THE ECONOMIC BENEFITS OF SMART GRID INITIATIVES

Initiative	Results
SAS	• Total NPV: $179,002,262 • EIRR: 41% • B/C ratio: 2.13 • Switching value: Avoided ENS per SAS = 75.9 MWh/year (assuming Transmission OPEX reduction benefit equal to zero)
WAMS	• Total NPV: $22,951,362 • EIRR: 204% • B/C ratio: 17.82 • Switching value: Percentage of events prevented = 4.94% (assuming Transmission OPEX reduction benefit equal to zero)
Lightning Location System	• Total NPV: $11,035,144 • EIRR: 164% • B/C ratio: 6.89 • Switching value: Percentage of events prevented = 21.3% (assuming Transmission OPEX reduction benefit equal to zero).

(Continued next page)

TABLE 55 (CONTINUED)

Initiative	Results
SVC	• Total NPV: $5,265,412 • EIRR: 14% • B/C ratio: 1.21 • Switching value: Percentage of events prevented = 60.3% (assuming Transmission OPEX reduction benefit equal to zero)
HVDC	• Total NPV: $23,524,111 • EIRR: All positive cash flows • B/C ratio: 1.56 • Switching value: Line length = 773 km (assuming Transmission OPEX reduction benefit equal to zero)
FLS	• Total NPV: $1,235,045 • EIRR: 13% • B/C ratio: 1.17 • Switching value: % monitored lines with faults = 64.1%
DGA	• Total NPV: $5,532,566 • EIRR: 12% • B/C ratio: 1.13 • Switching value: Average cost of a transformer fault = $7,907.
Dynamic Thermal Circuit Rating	• Total NPV: $44,132,102 • EIRR: All positive cash flows • B/C ratio: 35.11 • Switching value: Line reconductoring investment deferment = 0.18 years (assuming Transmission OPEX reduction benefit equal to zero)
GIS	• Total NPV: $762,214 • EIRR: 48% • B/C ratio: 3.61 • Switching value: % reduction of SAS O&M = 2.7%
Power quality monitoring and Metering Data Acquisition Systems	• Total NPV: $11,003,193 • EIRR: 797% • B/C ratio: 39.26 • Switching value: Percentage of events prevented = 10.0% (assuming Transmission OPEX reduction benefit equal to zero)

Source: Authors

G.2 Substation Automation System (SAS)

Table 56 shows that the costs are spread over a number of years and that over the same period the benefits increase because of the cumulative effects of old and new installed SAS. Maximum yearly value of costs is $34,000,000 in the first year of investment, while maximum yearly value of benefits of $69,000,000 occurs in the last few years of the timeline.

G.3 Wide Area Monitoring System (WAMS)

Table 57 shows that the major costs are concentrated in the first few years because of the huge implementation costs for the existing substations in the network. The benefits increase over the same period because of the cumulative effects of old and new installed PMUs. Maximum annual value of costs is $436,560, which occurs in the second year of investment; while maximum yearly value of benefits is $5,068,651 occur in the last few years of the timeline.

TABLE 56: SAS COSTS AND BENEFITS COMPARISON

DISCOUNT RATE	10.0%
INVESTMENT DURATION (YEARS)	15
Total NPV 2030 [$]	179 002 262
EIRR	41%
B/C ratio	2.13
Avoided ENS per SAS to break-even (considering Transmission OPEX reduction benefit equal to zero) [MWh/year]	75.9

Cost/unit	n.unit
2 400 000	5
900 000	13
2 400 000	45
900 000	105

Cost/year (absolute at 100% of deployment)	Cost/year (% Capex)
	1%
	1%
	1%
	1%

Hypothesis	
Number of SAS until 2014:	50
ENS cost ($/MWh)	3 000
Avoided ENS per SAS (MWh/year)	100
Transmission system OPEX reduction ($/year)	19 200 000

		unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	Total Benefits	USD	0	0	26 850 000	34 500 000	39 450 000	44 400 000	49 350 000	53 400 000	57 450 000	61 500 000	65 550 000	69 600 000	69 600 000	69 600 000	69 600 000	69 600 000
	a. Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000
	b. Reduction of Energy Not Served (ENS)	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Reduction of power losses	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Improve system reliability through reduced frequency and duration of system faults	USD	0	0	7 650 000	15 300 000	20 250 000	25 200 000	30 150 000	34 200 000	38 250 000	42 300 000	46 350 000	50 400 000	50 400 000	50 400 000	50 400 000	50 400 000
	e. Avoided CAPEX and Deferred Capacity Investments	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Costs	USD	0	34 466 250	34 807 500	23 180 250	23 403 000	23 625 750	19 758 000	19 940 250	20 122 500	20 304 750	20 487 000	2 262 000	2 262 000	2 262 000	2 262 000	2 262 000
	Total Costs Capex	USD	0	34 125 000	34 125 000	22 275 000	22 275 000	22 275 000	18 225 000	18 225 000	18 225 000	18 225 000	18 225 000	0	0	0	0	0
	Total Costs Opex	USD	0	341 250	682 500	905 250	1 128 000	1 350 750	1 533 000	1 715 250	1 897 500	2 079 750	2 262 000	2 262 000	2 262 000	2 262 000	2 262 000	2 262 000
		Planning (existing) -->	0%	50%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Cost	Planning (new) -->	0%	11%	11%	11%	11%	11%	9%	9%	9%	9%	9%	0%	0%	0%	0%	0%
CAPEX	500 kV substations retrofitting	USD	0	6 000 000	6 000 000	0	0	0	0	0	0	0	0	0	0	0	0	0
CAPEX	220 kV substations retrofitting	USD	0	5 850 000	5 850 000	0	0	0	0	0	0	0	0	0	0	0	0	0
CAPEX	500 kV new substations	USD	0	11 880 000	11 880 000	11 880 000	11 880 000	11 880 000	9 720 000	9 720 000	9 720 000	9 720 000	9 720 000	0	0	0	0	0
CAPEX	220 kV new substations	USD	0	10 395 000	10 395 000	10 395 000	10 395 000	10 395 000	8 505 000	8 505 000	8 505 000	8 505 000	8 505 000	0	0	0	0	0
OPEX	500 kV substations retrofitting	USD	0	60 000	120 000	120 000	120 000	120 000	120 000	120 000	120 000	120 000	120 000	120 000	120 000	120 000	120 000	120 000
OPEX	220 kV substations retrofitting	USD	0	58 500	117 000	117 000	117 000	117 000	117 000	117 000	117 000	117 000	117 000	117 000	117 000	117 000	117 000	117 000
OPEX	500 kV new substations	USD	0	118 800	237 600	356 400	475 200	594 000	691 200	788 400	885 600	982 800	1 080 000	1 080 000	1 080 000	1 080 000	1 080 000	1 080 000
OPEX	220 kV new substations	USD	0	103 950	207 900	311 850	415 800	519 750	604 800	689 850	774 900	859 950	945 000	945 000	945 000	945 000	945 000	945 000
BENEFITS	Number of substations		164	180	197	213	230	246	260	273	287	300	314	314	314	314	314	314
BENEFITS	Total existing Substations equipped with SAS		50	59	68	68	68	68	68	68	68	68	68	68	68	68	68	68
BENEFITS	New Substations equipped with SAS		0	17	33	50	66	83	96	110	123	137	150	150	150	150	150	150
BENEFITS	Substations equipped with SAS after 2015		0	26	51	68	84	101	114	128	141	155	168	168	168	168	168	168
BENEFITS	Installation pace for new substations		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BENEFITS	ENS reduction	MWh	0	0	2 550	5 100	6 750	8 400	10 050	11 400	12 750	14 100	15 450	16 800	16 800	16 800	16 800	16 800
BENEFITS	Improve system reliability through reduced frequency and duration of system faults	USD	0	0	7 650 000	15 300 000	20 250 000	25 200 000	30 150 000	34 200 000	38 250 000	42 300 000	46 350 000	50 400 000	50 400 000	50 400 000	50 400 000	50 400 000
BENEFITS	Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000	19 200 000

Source: Authors

TABLE 57: WAMS COSTS AND BENEFITS COMPARISON

DISCOUNT RATE	10.0%
INVESTMENT DURATION (YEARS)	15
Total NPV 2030 [$]	22 951 362
EIRR	204%
B/C ratio	17.82
% of events prevented to break-even (considering Transmission OPEX reduction benefit equal to zero)	4.94%

	unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Benefits	USD	0	0	0	3 683 479	3 759 817	3 842 484	3 927 478	4 020 774	4 123 311	4 236 110	4 360 285	4 476 314	4 603 945	4 744 339	4 898 773	5 068 651
a. Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	0	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000
b. Reduction of Energy Not Served (ENS)	USD	0	0	0	483 479	559 817	642 484	727 478	820 774	923 311	1 036 110	1 160 285	1 276 314	1 403 945	1 544 339	1 698 773	1 868 651
c. Reduction of power losses	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Improve system reliability through reduced frequency and duration of system faults	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Avoided CAPEX and Deferred Capacity Investments	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Costs	USD	0	432 280	436 560	141 880	143 200	144 520	121 600	122 680	123 760	124 840	125 920	17 920	17 920	17 920	17 920	17 920
Total Costs Capex	USD	0	428 000	428 000	132 000	132 000	132 000	108 000	108 000	108 000	108 000	108 000	0	0	0	0	0
Total Costs Opex	USD	0	4 280	8 560	9 880	11 200	12 520	13 600	14 680	15 760	16 840	17 920	17 920	17 920	17 920	17 920	17 920
Planning (existing) →		0%	50%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Cost — Planning (new) →		0%	11%	11%	11%	11%	11%	9%	9%	9%	9%	9%	0%	0%	0%	0%	0%
CAPEX — PMU installation 500 and 220 kV existing substations	USD	0	296 000	296 000	0	0	0	0	0	0	0	0	0	0	0	0	0
CAPEX — PMU installation 500 and 220 kV new substations	USD	0	132 000	132 000	132 000	132 000	132 000	108 000	108 000	108 000	108 000	108 000	0	0	0	0	0
OPEX — O&M PMU 500 and 220 kV existing substations	USD	0	2 960	5 920	5 920	5 920	5 920	5 920	5 920	5 920	5 920	5 920	5 920	5 920	5 920	5 920	5 920
OPEX — O&M PMU 500 and 220 kV new substations	USD	0	1 320	2 640	3 960	5 280	6 600	7 680	8 760	9 840	10 920	12 000	12 000	12 000	12 000	12 000	12 000
Faults events equivalent to a 10% brownout of 30 minute per year																	
BENEFITS — Number of substations		164	180	197	213	230	246	260	273	287	300	314	314	314	314	314	314
BENEFITS — Old Substation equipped with PMUs after 2015		0	37	74	74	74	74	74	74	74	74	74	74	74	74	74	74
BENEFITS — New Substation equipped with PMUs		0	17	33	50	66	83	96	110	123	137	150	150	150	150	150	150
BENEFITS — Substation equipped with PMUs		0	54	107	124	140	157	170	184	197	211	224	224	224	224	224	224
BENEFITS — installation pace of new substations		0%	11%	11%	11%	11%	11%	9%	9%	9%	9%	9%	0%	0%	0%	0%	0%
BENEFITS — Interruption cost	USD	3 135 375	3 448 913	3 793 804	4 173 184	4 590 503	5 049 553	5 554 508	6 109 959	6 720 955	7 393 050	8 132 355	8 945 591	9 840 150	10 824 165	11 906 581	13 097 239
BENEFITS — ENS	MWh	1 125	1 238	1 361	1 497	1 647	1 812	1 993	2 192	2 412	2 653	2 918	3 210	3 531	3 884	4 272	4 699
BENEFITS — Reduction of Energy Not Served	USD	0	0	0	483 479	559 817	642 484	727 478	820 774	923 311	1 036 110	1 160 285	1 276 314	1 403 945	1 544 339	1 698 773	1 868 651
BENEFITS — Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	0	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000

Cost/unit	n.unit	
8 000	74	CAPEX — PMU installation 500 and 220 kV existing substations
8 000	150	CAPEX — PMU installation 500 and 220 kV new substations

Cost/year (absolute at 100% of deployment)	Cost/year (% Capex)	
	1%	OPEX — O&M PMU 500 and 220 kV existing substations
	1%	OPEX — O&M PMU 500 and 220 kV new substations

Hypothesis	
Number of PMU until 2014:	4
% of events prevented	20%
Transmission system OPEX reduction ($/year)	3 200 000

Source: Authors

G.4 Lightning Location System (LLS)

Table 58 shows that the costs occur only in the first few years because of the installation of the LLS smart grid application (that is in addition to network expansion). The benefits increase over the time because of the cumulative effect on an increasingly extended power system. Maximum yearly value of costs is $1,090,000, which occurs in the second year of investment, while maximum yearly value of benefits of $2,284,862 occurs in the last year of the timeline.

TABLE 58: LIGHTNING LOCATION SYSTEM COSTS AND BENEFITS COMPARISON

DISCOUNT RATE	10.0%
INVESTMENT DURATION (YEARS)	15
Total NPV 2030 [$]	11 035 144
EIRR	164%
B/C ratio	6.89
% of events prevented to break-even (considering Transmission OPEX reduction benefit equal to zero)	21.3%

				unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
			Total Benefits	USD	0	0	1 789 690	1 808 659	1 829 525	1 852 478	1 877 725	1 905 498	1 936 048	1 969 653	2 006 618	2 047 280	2 092 007	2 141 208	2 195 329	2 254 862
			a. Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000
			b. Reduction of Energy Not Served (ENS)	USD	0	0	189 690	208 659	229 525	252 478	277 725	305 498	336 048	369 653	406 618	447 280	492 007	541 208	595 329	654 862
			c. Reduction of power losses	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			d. Improve system reliability through reduced frequency and duration of system faults	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			e. Avoided CAPEX and Deferred Capacity Investments	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			Total Costs	USD	0	671 000	1 090 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000
			Total Costs Capex	USD	0	640 000	1 028 000	0	0	0	0	0	0	0	0	0	0	0	0	0
			Total Costs Opex	USD	0	31 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000	62 000
Cost/unit	n.unit		Cost	Planning (new) -->	0%	50%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
54 000	20	CAPEX	Lightning detectors	USD	0	540 000	540 000	0	0	0	0	0	0	0	0	0	0	0	0	0
10 000	20		Civil works	USD	0	100 000	100 000	0	0	0	0	0	0	0	0	0	0	0	0	0
30 000	1		Telecommunication between detectors and control center, data collection and management (ADSL, Routers, DB's)	USD	0	0	30 000	0	0	0	0	0	0	0	0	0	0	0	0	0
172 000	1		Lightning Location Central Analyzer software	USD	0	0	172 000	0	0	0	0	0	0	0	0	0	0	0	0	0
186 000	1		Archiving and handling of Lightning data software	USD	0	0	186 000	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost/year (absolute at 100% of deployment)	Cost/year (% Capex)																			
10 000		OPEX	Site rental	USD	0	5 000	10 000	10 000	10 000	10 000	10 000	10 000	10 000	10 000	10 000	10 000	10 000	10 000	10 000	10 000
4 000			Electricity supply	USD	0	2 000	4 000	4 000	4 000	4 000	4 000	4 000	4 000	4 000	4 000	4 000	4 000	4 000	4 000	4 000
24 000			Data analysis	USD	0	12 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000
24 000			Hardware and software operation and maintenance	USD	0	12 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000	24 000
Hypothesis			Faults events equivalent to a 2% brownout of 30 minutes per year																	
% of events prevented	25%	BENEFITS	Interrupion cost	USD	627 075	689 783	758 761	834 637	918 101	1 009 911	1 110 902	1 221 992	1 344 191	1 478 610	1 626 471	1 789 118	1 968 030	2 164 833	2 381 316	2 619 448
Transmission system OPEX reduction ($/year)	1 600 000		ENS	MWh	225	248	272	299	329	362	399	438	482	531	584	642	706	777	854	940
			Reduction of Energy Not Served	USD	0	0	189 690	208 659	229 525	252 478	277 725	305 498	336 048	369 653	406 618	447 280	492 007	541 208	595 329	654 862
			Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000

Source: Authors

G.5 Static Var Compensator (SVC)

Table 59 shows that the costs are present only in the first few years because of the installation of the SVC smart grid application. The benefits increase over the time because of the cumulative effect on an increasingly extended power system. Maximum yearly value of costs is $7,968,000, which occurs in the second year of investment, while maximum yearly value of benefits of $6,474,410 occur in the last year of the timeline.

TABLE 59: SVC COSTS AND BENEFITS COMPARISON

DISCOUNT RATE	10.0%
INVESTMENT DURATION (YEARS)	15
Total NPV 2030 [$]	5 265 412
EIRR	14.21%
B/C ratio	1.21
% of events prevented to break-even (considering Transmission OPEX reduction benefit equal to zero)	60.3%

				unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
			Total Benefits	USD	0	1 015 557	2 074 225	3 182 472	4 347 626	4 462 388	4 588 627	4 727 490	4 880 239	5 048 263	5 233 089	5 436 398	5 660 037	5 906 041	6 176 645	6 474 310
			a. Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	800 000	1 600 000	2 400 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000
			b. Reduction of Energy Not Served (ENS)	USD	0	215 557	474 225	782 472	1 147 626	1 262 388	1 388 627	1 527 490	1 680 239	1 848 263	2 033 089	2 236 398	2 460 037	2 706 041	2 976 645	3 274 310
			c. Reduction of power losses	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			d. Improve system reliability through reduced frequency and duration of system faults	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			e. Avoided CAPEX and Deferred Capacity Investments	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			Total Costs	USD	0	7 898 250	7 921 500	7 944 750	7 968 000	93 000	93 000	93 000	93 000	93 000	93 000	93 000	93 000	93 000	93 000	93 000
			Total Costs Capex	USD	0	7 875 000	7 875 000	7 875 000	7 875 000	0	0	0	0	0	0	0	0	0	0	0
			Total Costs Opex	USD	0	23 250	46 500	69 750	93 000	93 000	93 000	93 000	93 000	93 000	93 000	93 000	93 000	93 000	93 000	93 000
Cost/Mvar	Mvar		Cost	Planning (new) -->	0%	25%	25%	25%	25%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
30 000	900	CAPEX	Static Var Compensator (relocatable)	USD	0	6 750 000	6 750 000	6 750 000	6 750 000	0	0	0	0	0	0	0	0	0	0	0
5 000	900	CAPEX	Civil works	USD	0	1 125 000	1 125 000	1 125 000	1 125 000	0	0	0	0	0	0	0	0	0	0	0
Cost/year (absolute at 100% of deployment)	Cost/year (% Capex)																			
60 000		OPEX	Preventive maintenance (3 days/year) + On-line support	USD	0	15 000	30 000	45 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000
30 000		OPEX	Corrective maintenance	USD	0	7 500	15 000	22 500	30 000	30 000	30 000	30 000	30 000	30 000	30 000	30 000	30 000	30 000	30 000	30 000
3 000		OPEX	Spares e consumables	USD	0	750	1 500	2 250	3 000	3 000	3 000	3 000	3 000	3 000	3 000	3 000	3 000	3 000	3 000	3 000
Hypothesis			Faults events equivalent to a 10% brownout of 30 minutes per year																	
% of events prevented (100% of deployment)	25%	BENEFITS	Interrupion cost	USD	3 135 375	3 448 913	3 793 804	4 173 184	4 590 503	5 049 553	5 554 508	6 109 959	6 720 955	7 393 050	8 132 355	8 945 591	9 840 150	10 824 165	11 906 581	13 097 239
Transmission system OPEX reduction ($/year)	3 200 000	BENEFITS	ENS	MWh	1 125	1 238	1 361	1 497	1 647	1 812	1 993	2 192	2 412	2 653	2 918	3 210	3 531	3 884	4 272	4 699
		BENEFITS	Reduction of Energy Not Served	USD	0	215 557	474 225	782 472	1 147 626	1 262 388	1 388 627	1 527 490	1 680 239	1 848 263	2 033 089	2 236 398	2 460 037	2 706 041	2 976 645	3 274 310
		BENEFITS	Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	800 000	1 600 000	2 400 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000	3 200 000

Source: Authors

G.6 High Voltage Direct Current (HVDC) technology

Table 60 shows that the costs are only in the first few years owing to the construction phase of the HVDC system. The benefits do not change over the time because of the assumption of power losses cost is the same over the period. Maximum yearly value of incremental costs is $8,748,000 in the last part of the timeline due to the high incremental OPEX, while the yearly value of benefits is $12,800,000.

TABLE 60: HVDC COSTS AND BENEFITS COMPARISON

DISCOUNT RATE	10.0%
INVESTMENT DURATION (YEARS)	15
Total NPV 2030 [$]	23 524 111
EIRR	ALL POSITIVE CASH FLOWS
B/C ratio	1.56
Line length [km] to break-even (considering Transmission OPEX reduction benefit equal to zero)	773

		unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	Total Benefits	USD	0	0	0	0	12 800 000	12 800 000	12 800 000	12 800 000	12 800 000	12 800 000	12 800 000	12 800 000	12 800 000	12 800 000	12 800 000	12 800 000
	a. Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	0	0	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000
	b. Reduction of Energy Not Served (ENS)	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Reduction of power losses	USD	0	0	0	0	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000
	d. Improve system reliability through reduced frequency and duration of system faults	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Avoided CAPEX and Deferred Capacity Investments	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Costs	USD	0	-2 013 000	174 000	2 361 000	4 548 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000
	Total Costs Capex	USD	0	-4 200 000	-4 200 000	-4 200 000	-4 200 000	0	0	0	0	0	0	0	0	0	0	0
	Total Costs Opex	USD	0	2 187 000	4 374 000	6 561 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000	8 748 000
	Cost	Planning (new) -->	0%	25%	25%	25%	25%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CAPEX	HVDC Overhead lines engineering, procurement and construction	USD	0	69 000 000	69 000 000	69 000 000	69 000 000	0	0	0	0	0	0	0	0	0	0	0
CAPEX	HVDC Converter stations	USD	0	100 000 000	100 000 000	100 000 000	100 000 000	0	0	0	0	0	0	0	0	0	0	0
CAPEX	HVAC Overhead lines engineering, procurement and construction (Avoided Capex)	USD	0	-112 000 000	-112 000 000	-112 000 000	-112 000 000	0	0	0	0	0	0	0	0	0	0	0
CAPEX	HVAC Cost of additional equipment (Substations, feeders, Facts, ...) (Avoided Capex)	USD	0	-11 200 000	-11 200 000	-11 200 000	-11 200 000	0	0	0	0	0	0	0	0	0	0	0
CAPEX	HVAC additional right of way cost (Avoided Capex)	USD	0	-50 000 000	-50 000 000	-50 000 000	-50 000 000	0	0	0	0	0	0	0	0	0	0	0
OPEX	HVDC OHL O&M	USD	0	1 035 000	2 070 000	3 105 000	4 140 000	4 140 000	4 140 000	4 140 000	4 140 000	4 140 000	4 140 000	4 140 000	4 140 000	4 140 000	4 140 000	4 140 000
OPEX	HVDC O&M Converter stations	USD	0	3 000 000	6 000 000	9 000 000	12 000 000	12 000 000	12 000 000	12 000 000	12 000 000	12 000 000	12 000 000	12 000 000	12 000 000	12 000 000	12 000 000	12 000 000
OPEX	HVAC OHL O&M (Avoided Opex)	USD	0	-1 848 000	-3 696 000	-5 544 000	-7 392 000	-7 392 000	-7 392 000	-7 392 000	-7 392 000	-7 392 000	-7 392 000	-7 392 000	-7 392 000	-7 392 000	-7 392 000	-7 392 000
OPEX		USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OPEX		USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BENEFITS	Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	0	0	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000
BENEFITS	Reduction of power losses	USD	0	0	0	0	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000	11 200 000

Cost/unit	unit
345 000	800
200 000 000	2
560 000	800
44 800 000	1
Righ-of-Way width reduction [m]	25
Right-of-Way average cost [$/m ²]	10
Cost/year (absolute at 100% of deployment)	Cost/year (% Capex)
	1.5%
	3%
	1.5%

Hypothesis	
Cost of losses HVDC lines [$/km/year]	40 000
Cost of losses HVDC converters [$/year]	8 800 000
Cost of losses AC lines [$/km/year]	65 000
Transmission system OPEX reduction ($/year)	1 600 000

Source: Authors

G.7 Fault Locator System (FLS)

Table 61 reports that the major costs are only in the first few years because of the installation of the FLS smart grid application. The benefits increase over the time because of the cumulative effect on an increasingly extended power system. Maximum yearly value of costs is $4,200,000 in the first year of investment, while maximum yearly value of benefits of $2,455,732 occurs in the last year of the timeline.

TABLE 61: FLS COSTS AND BENEFITS COMPARISON

DISCOUNT RATE	10.0%
INVESTMENT DURATION (YEARS)	15
Total NPV 2030 [$]	1 235 045
EIRR	13%
B/C ratio	1.17
% monitored lines with faults to break-even	64.1%

	unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Benefits	USD	0	323 336	711 338	782 472	860 719	946 791	1 041 470	1 145 617	1 260 179	1 386 197	1 524 817	1 677 298	1 845 028	2 029 531	2 232 484	2 455 732
a. Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b. Reduction of Energy Not Served (ENS)	USD	0	323 336	711 338	782 472	860 719	946 791	1 041 470	1 145 617	1 260 179	1 386 197	1 524 817	1 677 298	1 845 028	2 029 531	2 232 484	2 455 732
c. Reduction of power losses	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Improve system reliability through reduced frequency and duration of system faults	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Avoided CAPEX and Deferred Capacity Investments	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Costs	USD	0	4 200 000	4 200 000	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Costs Capex	USD	0	4 200 000	4 200 000	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Costs Opex	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Cost/unit	unit		Cost	Planning (new) -->	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
					0%	50%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
60 000	140	CAPEX	Equipment	USD	0	4 200 000	4 200 000	0	0	0	0	0	0	0	0	0	0	0	0	0

Hypothesis			Faults events equivalent to a 10 % brownout of 30 minutes per year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
% of outage time duration	25%	BENEFITS	Interrupion cost	USD	3 135 375	3 448 913	3 793 804	4 173 184	4 590 503	5 049 553	5 554 508	6 109 959	6 720 955	7 393 050	8 132 355	8 945 591	9 840 150	10 824 165	11 906 581	13 097 239
% monitored lines with faults at 100% of deployment)	75%		ENS	MWh	1 125	1 238	1 361	1 497	1 647	1 812	1 993	2 192	2 412	2 653	2 918	3 210	3 531	3 884	4 272	4 699
			Reduction of Energy Not Served	USD	0	323 336	711 338	782 472	860 719	946 791	1 041 470	1 145 617	1 260 179	1 386 197	1 524 817	1 677 298	1 845 028	2 029 531	2 232 484	2 455 732

Source: Authors

G.8 On-line Dissolved Gas-in-oil Analysis (DGA)

Table 62 shows that the costs are spread over the years and the benefits increase because of the cumulative effects of old and new installed sensors. Maximum yearly value of costs is $7,300,785, which occurs in the second year of investment, while maximum yearly value of benefits of $12,425,508 occurs in the last year of the timeline.

TABLE 62: DGA COSTS AND BENEFITS COMPARISON

DISCOUNT RATE	10.0%
INVESTMENT DURATION (YEARS)	15
Total NPV 2030 [$]	5 532 566
EIRR	12%
B/C ratio	1.13
Average cost of a transformer fault [$] to break-even	7907

		unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	Total Benefits	USD	0	1 363 768	2 727 537	3 495 955	4 264 374	5 032 792	5 859 505	6 686 217	7 512 929	8 339 642	9 166 354	9 818 185	10 470 015	11 121 846	11 773 677	12 425 508
	a. Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Reduction of Energy Not Served (ENS)	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Reduction of power losses	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Improve system reliability through reduced frequency and duration of system faults	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Avoided CAPEX and Deferred Capacity Investments	USD	0	1 363 768	2 727 537	3 495 955	4 264 374	5 032 792	5 859 505	6 686 217	7 512 929	8 339 642	9 166 354	9 818 185	10 470 015	11 121 846	11 773 677	12 425 508
	Total Costs	USD	0	7 264 643	7 300 785	5 099 798	5 124 810	5 149 823	5 556 233	5 583 143	5 610 053	5 636 963	5 663 873	4 546 590	4 567 808	4 589 025	4 610 243	4 631 460
	Total Costs Capex	USD	0	7 228 500	7 228 500	5 002 500	5 002 500	5 002 500	5 382 000	5 382 000	5 382 000	5 382 000	5 382 000	4 243 500	4 243 500	4 243 500	4 243 500	4 243 500
	Total Costs Opex	USD	0	36 143	72 285	97 298	122 310	147 323	174 233	201 143	228 053	254 963	281 873	303 090	324 308	345 525	366 743	387 960
		Planning (existing) ->	0%	50%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Cost	Planning (new) -->	0%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	6%	6%	6%	6%	6%
CAPEX	Sensors on existing transformers	USD	0	2 226 000	2 226 000	0	0	0	0	0	0	0	0	0	0	0	0	0
CAPEX	Sensors on new transformers	USD	0	5 002 500	5 002 500	5 002 500	5 002 500	5 002 500	5 382 000	5 382 000	5 382 000	5 382 000	5 382 000	4 243 500	4 243 500	4 243 500	4 243 500	4 243 500
OPEX	O&M DGA existing transformers	USD	0	11 130	22 260	22 260	22 260	22 260	22 260	22 260	22 260	22 260	22 260	22 260	22 260	22 260	22 260	22 260
OPEX	O&M DGA new transformers	USD	0	25 013	50 025	75 038	100 050	125 063	151 973	178 883	205 793	232 703	259 613	280 830	302 048	323 265	344 483	365 700
BENEFITS	Avoided CAPEX	USD	0	1 363 768	2 727 537	3 495 955	4 264 374	5 032 792	5 859 505	6 686 217	7 512 929	8 339 642	9 166 354	9 818 185	10 470 015	11 121 846	11 773 677	12 425 508

Cost/unit	unit	
106 000	42	Sensors on existing transformers
106 000	690	Sensors on new transformers

Cost/year (absolute at 100% of deployment)	Cost/year (% Capex)	
	0.5%	O&M DGA existing transformers
	0.5%	O&M DGA new transformers

Hypothesis	
Fault probability	0.60%
Average cost of a transformer fault [$/MVA]	9 000
New capacity to be installed [MVA]	208 052

Source: Authors

G.9 Dynamic Thermal Circuit Rating (DTCR)

Table 63 shows that the costs are only in the first few years owing to the installation phase on the monitored lines. The benefits are also mainly in the first part of the timeline because of the immediately avoided CAPEX achieved with the technology. Maximum yearly value of incremental costs is $665,600 occurring in the second year of investment, while maximum yearly value of benefits is $21,600,000.

TABLE 63: DTCR COSTS AND BENEFITS COMPARISON

DISCOUNT RATE	10.0%
INVESTMENT DURATION (YEARS)	15
Total NPV 2030 [$]	44 132 102
EIRR	ALL POSITIVE CASH FLOWS
B/C ratio	35.11
Number of year deferred to break-even (considering Transmission OPEX reduction benefit equal to zero)	0.18

	unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Benefits	USD	0	20 000 000	21 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000
a. Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000
b. Reduction of Energy Not Served (ENS)	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
c. Reduction of power losses	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Improve system reliability through reduced frequency and duration of system faults	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Avoided CAPEX and Deferred Capacity Investments	USD	0	20 000 000	20 000 000	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Costs	USD	0	652 800	665 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600
Total Costs Capex	USD	0	640 000	640 000	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Costs Opex	USD	0	12 800	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600
Cost	Planning (new) -->	0%	50%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Sensors	USD	0	640 000	640 000	0	0	0	0				0	0	0	0	0	0
O&M DTCR	USD	0	12 800	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600	25 600
Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000

Cost/unit	unit
32 000	40
Line lenght:	100
Number of lines	4
Number of sensors per 100 km	10
Cost/year (absolute at 100% of deployment)	Cost/year (% Capex)
	2.0%
Cost of line reconductoring [$/km]	200 000
Number of years deferred	5
Number of avoided line reconductoring	4
Transmission system OPEX reduction ($/year)	1 600 000

Source: Authors

G.10 Geographic Information Systems (GIS)

Table 64 shows that the major costs are only in the first few years because of the installation of this new smart grid application. The benefits increase over the time because of the cumulative effect on an increasingly extended power system. Maximum yearly value of costs is $192,500 in the first year of investment, while maximum yearly value of benefits of $226,200 occurs in the last years of the timeline.

TABLE 64: GIS COSTS AND BENEFITS COMPARISON

DISCOUNT RATE	10.0%
INVESTMENT DURATION (YEARS)	15
Total NPV 2030 [$]	762 214
EIRR	48%
B/C ratio	3.61
% reduction of SAS O&M to break-even	2.70%

				unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
			Total Benefits	USD	0	0	68 250	90 525	112 800	135 075	153 300	171 525	189 750	207 975	226 200	226 200	226 200	226 200	226 200	226 200
			a. Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	68 250	90 525	112 800	135 075	153 300	171 525	189 750	207 975	226 200	226 200	226 200	226 200	226 200	226 200
			b. Reduction of Energy Not Served (ENS)	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			c. Reduction of power losses	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			d. Improve system reliability through reduced frequency and duration of system faults	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			e. Avoided CAPEX and Deferred Capacity Investments	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			Total Costs	USD	0	192 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500
			Total Costs Capex	USD	0	175 000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			Total Costs Opex	USD	0	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500
Cost/unit	unit		Cost	Planning (new) -->	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
150 000	1	CAPEX	Software applications	USD	0	150 000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 000	1		Hardware equipments	USD	0	25 000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost/year (absolute at 100% of deployment)	Cost/year (% Capex)																			
	10.0%	OPEX	Hardware and software maintenance	USD	0	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500	17 500
Hypothesis																				
% O&M of SAS	10.0%	BENEFITS	Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	68 250	90 525	112 800	135 075	153 300	171 525	189 750	207 975	226 200	226 200	226 200	226 200	226 200	226 200

Source: Authors

G.11 Power quality monitoring and Metering Data Acquisition Systems

Table 65 reports that the major costs are present mainly in the first few years because of the implementation this technology in the power system. The benefits increase over the time because of the cumulative effects of old and new installed analyzers in the expanding network. Maximum yearly value of costs is $203,051 in the first year of investment, while maximum yearly value of benefits of $1,794,110 occurs in the last years of the timeline.

TABLE 65: POWER QUALITY MONITORING AND METERING DATA ACQUISITION SYSTEMS COSTS AND BENEFITS COMPARISON

DISCOUNT RATE	10.0%
INVESTMENT DURATION (YEARS)	15
Total NPV 2030 [$]	11 003 193
EIRR	797%
B/C ratio	39.26
% of events prevented to break-even (considering Transmission OPEX reduction benefit equal to zero)	10.0%

				unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
			Total Benefits	USD	0	0	1 635 243	1 641 996	1 649 747	1 658 628	1 668 064	1 678 791	1 690 983	1 704 826	1 720 527	1 732 580	1 745 838	1 760 422	1 776 464	1 794 110
			a. Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000
			b. Reduction of Energy Not Served (ENS)	USD	0	0	35 243	41 996	49 747	58 628	68 064	78 791	90 983	104 826	120 527	132 580	145 838	160 422	176 464	194 110
			c. Reduction of power losses	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			d. Improve system reliability through reduced frequency and duration of system faults	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			e. Avoided CAPEX and Deferred Capacity Investments	USD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			Total Costs	USD	0	203 051	17 331	17 699	18 090	18 482	16 682	16 983	17 307	17 632	17 957	7 500	7 500	7 500	7 500	7 500
			Total Costs Capex	USD	0	198 742	12 630	12 606	12 606	12 606	10 481	10 457	10 457	10 457	10 457	0	0	0	0	0
			Total Costs Opex	USD	0	4 309	4 701	5 093	5 484	5 876	6 201	6 526	6 851	7 175	7 500	7 500	7 500	7 500	7 500	7 500
				Planning (software) -->	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Cost/unit	unit		Cost	Planning (new) -->	0%	57%	5%	5%	5%	5%	4%	4%	4%	4%	4%	0%	0%	0%	0%	0%
2 300	105	CAPEX	Equipment	USD	0	138 742	12 630	12 606	12 606	12 606	10 481	10 457	10 457	10 457	10 457	0	0	0	0	0
60 000	1		Software licence and hardware in the control center	USD	0	60 000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost/year (absolute at 100% of deployment)	Cost/year (% Capex)																			
6 000		OPEX	O&M control center + software updates	USD	0	3 447	3 761	4 074	4 387	4 700	4 961	5 221	5 480	5 740	6 000	6 000	6 000	6 000	6 000	6 000
1 500			Data analysis	USD	0	862	940	1 019	1 097	1 175	1 240	1 305	1 370	1 435	1 500	1 500	1 500	1 500	1 500	1 500
Hypothesis			Faults events equivalent to a 1% brownout of 15 minutes per year																	
% of events prevented (100% of deployment)	20%	BENEFITS	Interrupion cost	USD	232 342	255 576	281 134	309 247	340 172	374 189	411 608	452 769	498 046	547 851	602 636	662 899	729 189	802 108	882 319	970 551
Transmission system OPEX reduction ($/year)	1 600 000		ENS	MWh	56	62	68	75	82	91	100	110	121	133	146	160	177	194	214	235
			Reduction of Energy Not Served	USD	0	0	35 243	41 996	49 747	58 628	68 064	78 791	90 983	104 826	120 527	132 580	145 838	160 422	176 464	194 110
			Direct Transmission OPEX reduction (automation and operational efficiency)	USD	0	0	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000	1 600 000

Source: Authors

H. Sensitivity Analysis

H.1 Key Points Summary

The Sensitivity Analysis is an approach used for investigating the impact of changes in the variables of projects relative to the baseline scenario as described in the previous chapters.

The variables assumed for the assessment vary depending on the project under investigation. For this reason each Smart Grid initiative has been analyzed in order to identify those variables that are characterized by a high uncertainty and at the same time have a great impact on the economic evaluation.

Table 66 summarizes the sensitivity analysis parameters of each Smart Grid initiative.

H.2 Energy Not Served value sensitivity analysis

Table 66 shows that many Smart Grid applications are heavily dependent on the financial value assumed for energy not served (or Value of Loss Load).

The economic results are derived by conducting the sensitivity analysis on the ENS value for all the initiatives affected by this parameter and are shown below in Table 67 (NPV), Table 68 (EIRR) and Table 69 (B/C ratio). The results of the baseline scenario are listed in bold.

TABLE 66: SUMMARY OF THE SENSITIVITY ANALYSIS PARAMETERS OF SMART GRID INITIATIVES

Initiative	Sensitivity analysis parameters
SAS	Energy Not Served value Average value of annually ENS reduction per substation equipped with SAS
WAMS	Energy Not Served value Percentage of fault events prevented
Lightning Location System	Energy Not Served value Percentage of fault events prevented
SVC	Energy Not Served value Percentage of fault events prevented
HVDC	Power losses cost Line length
FLS	Energy Not Served value Reduction of outage time duration Percentage of lines with faults monitored by FLS
DGA	Average cost of a transformer fault
Dynamic Thermal Circuit Rating	Number of lines with deferred reconductoring Number of years of deferred investment
GIS	Operation and maintenance cost savings for SAS application
Power quality monitoring and Metering Data Acquisition Systems	Energy Not Served value Percentage of fault events prevented

Source: Authors

TABLE 67: NPV FOR DIFFERENT ENS VALUE ASSUMPTION

	Total NPV [$]			
ENS VALUE $/MWh -->	2,000 $/MWh	2,500 $/MWh	3,000 $/MWh	3,500 $/MWh
SAS	109,276,276	144,139,269	179,002,262	213,865,256
WAMS	21,107,844	22,031,389	22,951,362	23,874,906
LLS	10,303,557	10,670,059	11,035,144	11,401,647
SVC	1,738,115	3,505,181	5,265,412	7,032,478
FLS	(1,606,389)	(182,919)	1,235,045	2,658,514
PQ + Metering	10,811,319	10,907,461	11,003,193	11,099,336

Source: Authors

TABLE 68: ECONOMIC INTERNAL RATE OF RETURN FOR DIFFERENT ENS VALUE ASSUMPTION

	EIRR			
ENS VALUE $/MWh -->	2,000 $/MWh	2,500 $/MWh	3,000 $/MWh	3,500 $/MWh
SAS	31%	36%	41%	46%
WAMS	198%	201%	204%	208%
LLS	156%	160%	164%	168%
SVC	11%	13%	14%	16%
FLS	6%	10%	13%	16%
PQ + Metering	791%	794%	797%	800%

Source: Authors

TABLE 69: B/C RATIO FOR DIFFERENT ENS VALUE ASSUMPTION

	B/C ratio			
ENS VALUE $/MWh -->	2,000 $/MWh	2,500 $/MWh	3,000 $/MWh	3,500 $/MWh
SAS	1.69	1.91	2.13	2.35
WAMS	16.46	17.14	17.82	18.49
LLS	6.50	6.69	6.89	7.08
SVC	1.07	1.14	1.21	1.28
FLS	0.78	0.97	1.17	1.36
PQ + Metering	38.59	38.92	39.26	39.59

Source: Authors

H.3 Substation Automation System (SAS)

The variable that has the greatest potential for affecting the final net benefit considerably is the average value of annual ENS reduction per substation equipped with SAS (100 MWh in the baseline scenario).

Figure 91 shows the change of the economic indicators for ENS reduction (B/C ratio and Total NPV) varying from 50 MWh/year to 125 MWh/year for every substation equipped with SAS.

Owing to the high value of the EIRR in the baseline scenario no sensitivity analysis has been performed on the discount rate.

H.4 Wide Area Monitoring System (WAMS)

The variable that has the potential for affecting the final net benefit considerably is the percentage of fault events prevented (20% in the baseline scenario).

Figure 92 shows the effect on the economic indicators (B/C ratio and Total NPV) caused by varying the percentage of fault events prevented from 10% to 25%.

Due to the high value of the EIRR in the baseline scenario no sensitivity has been performed on the discount rate.

H.5 Lightning Location System (LLS)

The variable that has the potential for affecting the final net benefit considerably is the percentage of fault events prevented (25% in the baseline scenario).

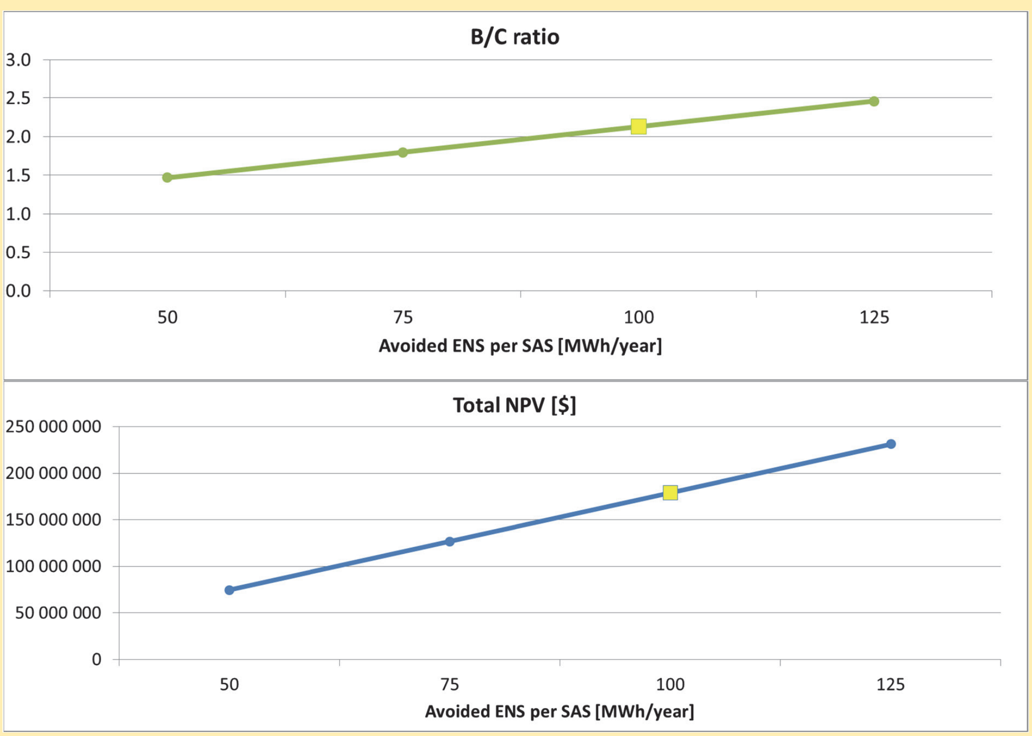
Figure 93 shows the effect on the economic indicators (B/C ratio and Total NPV) caused by varying the percentage of fault events prevented from 10% to 30%.

Due to the high value of the EIRR in the baseline scenario no sensitivity has been performed on the discount rate.

H.6 Static Var Compensator (SVC)

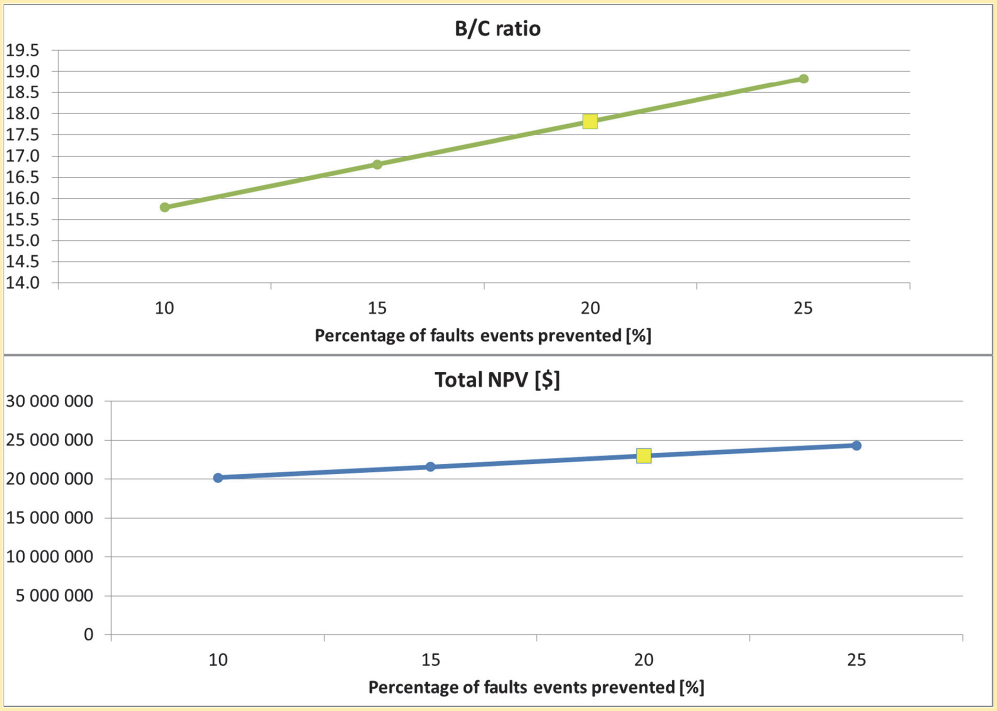
The variable that has the potential for affecting alter the final net benefit considerably is the percentage of fault events prevented (25% in the baseline scenario).

FIGURE 91: SAS SENSITIVITY ANALYSIS



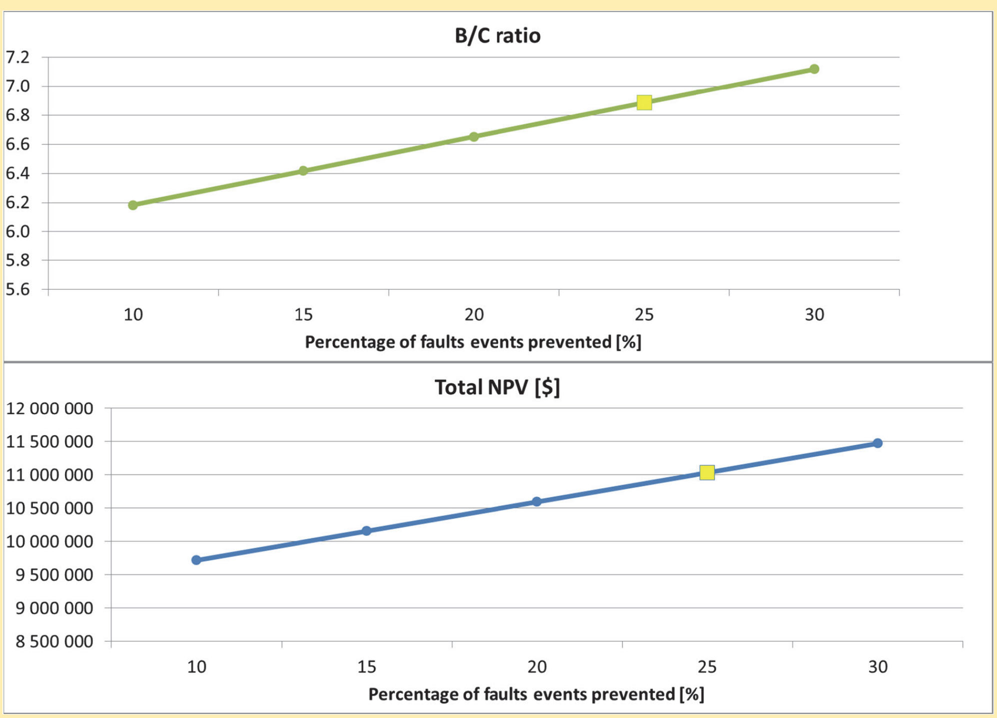
Source: Authors

FIGURE 92: WAMS SENSITIVITY ANALYSIS



Source: Authors

FIGURE 93: LIGHTNING LOCATION SYSTEM SENSITIVITY ANALYSIS



Source: Authors

Figure 94 shows the effect on the economic indicators (B/C ratio and Total NPV) caused by varying the percentage of fault events prevented from 10% to 30%.

H.7 High Voltage Direct Current (HVDC) technology

The variables that have the potential for affecting the final net benefit considerably are:

a. Power losses cost (60 \$/MWh in the baseline scenario);

b. Line length (800 km in the baseline scenario).

Figure 95 shows the effect on the economic indicators (B/C ratio and Total NPV) caused by varying the power losses cost from 40 \$/MWh to 80 \$/MWh.

Figure 96 shows the effect on the economic indicators (B/C ratio and Total NPV) caused by varying a power line length from 700 km to 950 km. As can be seen, when the line length is greater than 850 km the cost of a new HVAC link is greater than for a HVDC line which is indicated as a negative incremental cost.

H.8 Fault Locator System (FLS)

The variables that have the potential for affecting the final net benefit considerably are:

a. Reduction of outage duration (25% in the Baseline scenario);

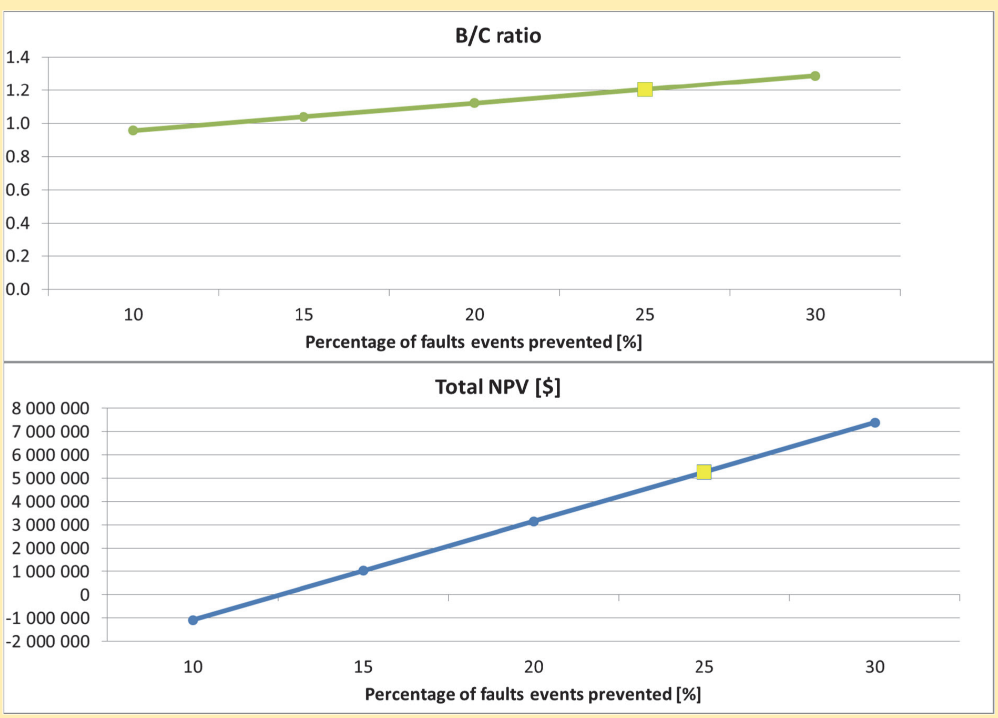
b. Percentage of lines with faults monitored with the FLS (10% in the baseline scenario).

As shown in Figure 97, the "Reduction of energy not served" benefit of FLS is proportional to the product of the two variables, for this reason a single sensitivity analysis can be performed by changing the values from the minimum to their maximum at the same time for both variables.

H.9 On-line Dissolved Gas-in-oil Analysis (DGA)

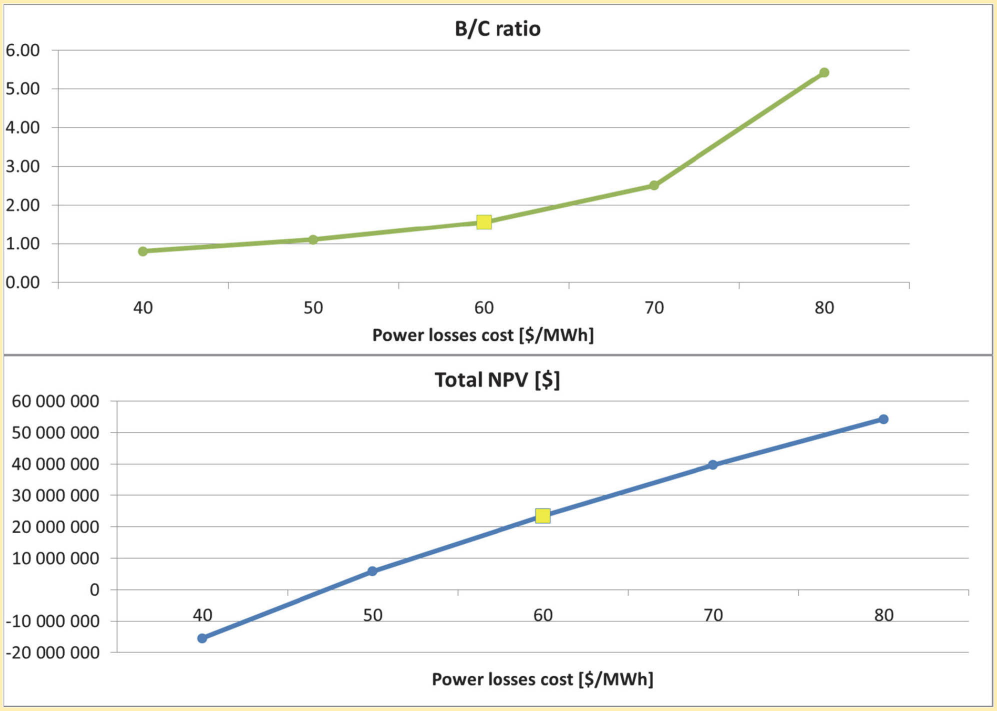
The variable that has the potential for affecting the final net benefit considerably is the average cost of a transformer fault (\$9,000 in the baseline scenario).

FIGURE 94: SVC SENSITIVITY ANALYSIS



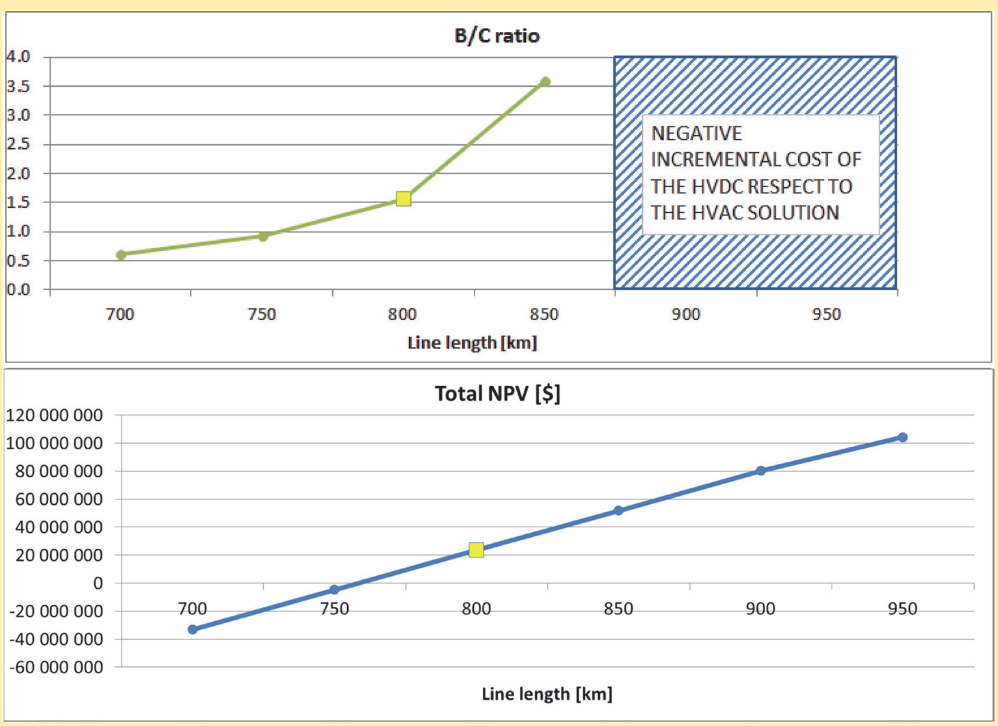
Source: Authors

FIGURE 95: HVDC SENSITIVITY ANALYSIS ON POWER LOSSES COST



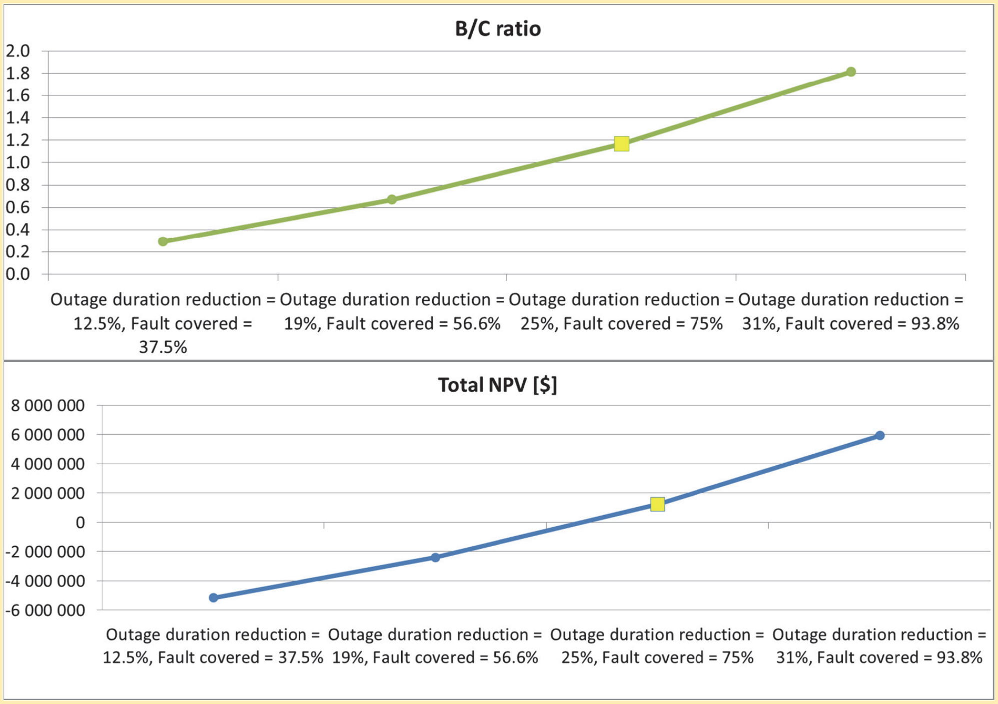
Source: Authors

FIGURE 96: HVDC SENSITIVITY ANALYSIS ON LINE LENGTH



Source: Authors

FIGURE 97: FLS SENSITIVITY ANALYSIS



Source: Authors

Figure 98 shows the effect on the economic indicators (B/C ratio and Total NPV) caused by varying the average cost of a transformer fault value from $6,750 to $11,250.

H.10 Dynamic Thermal Circuit Rating (DTCR)

The variables that have the potential for affecting alter the final net benefit considerably are:

a. Number of lines with deferred reconductoring (4 in the baseline scenario);

b. Number of years of deferred investment (5 in the baseline scenario).

As shown in Figure 99 the "Avoided CAPEX and Deferred Capacity Investments", which is a benefit of DTCR is proportional to the product of the two variables thus allowing a single sensitivity analysis to be performed for both variables by changing the values from the minimum to their maximum.

Due to the high value of the EIRR in the baseline scenario no sensitivity has been performed on the discount rate.

H.11 Geographic Information Systems (GIS)

The variable that has the potential for affecting the final net benefit considerably is the operation and maintenance cost savings generated by the SAS application (10% the baseline scenario).

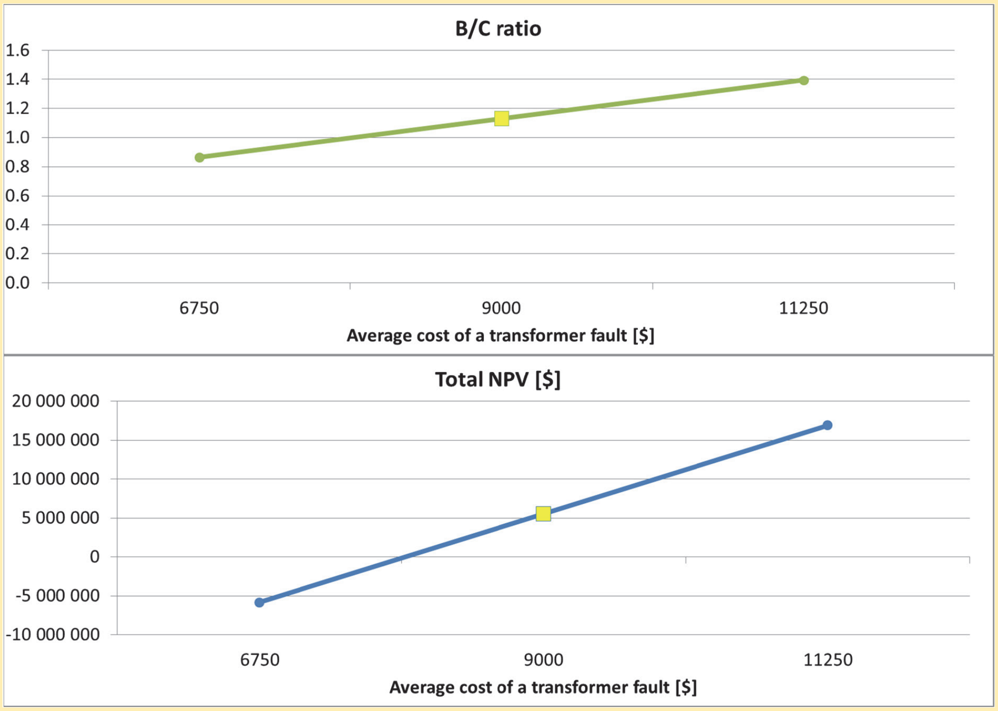
Figure 100 shows the effect on the economic indicators (B/C ratio and Total NPV) caused by varying the average cost of a transformer fault value from 5% to 12.5%.

H.12 Power quality monitoring and Metering Data Acquisition Systems

The variable that has the potential for affecting the final net benefit considerably is the percentage of faults events prevented (20% the baseline scenario).

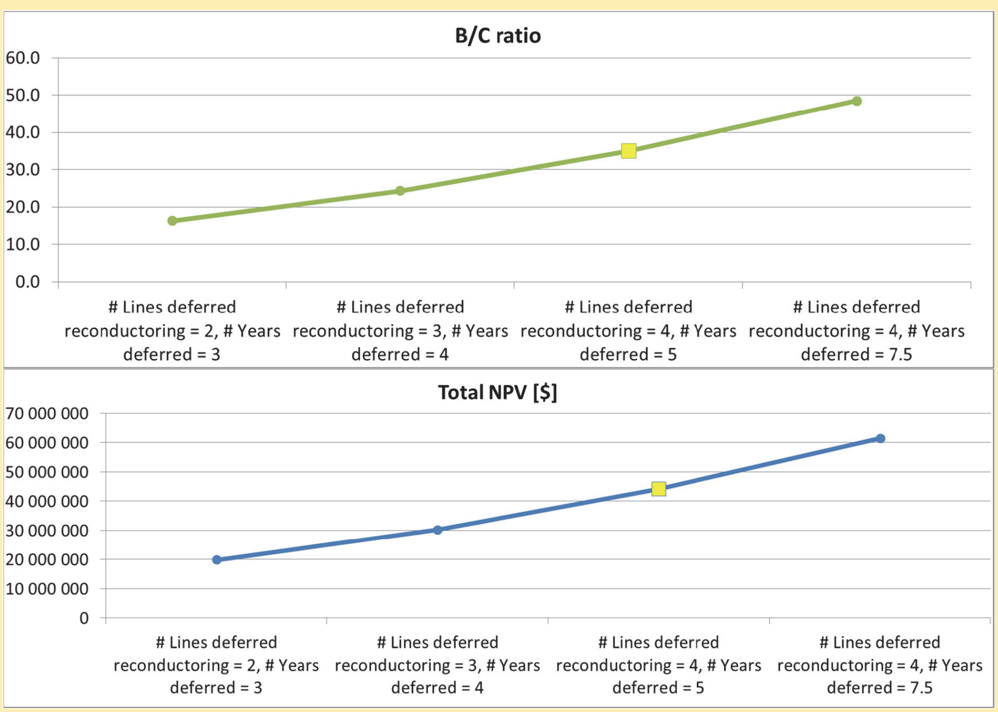
Figure 101 shows the effect on the economic indicators (B/C ratio and Total NPV) caused by varying the percentage of faults events prevented from 10% to 25%.

FIGURE 98: DGA SENSITIVITY ANALYSIS



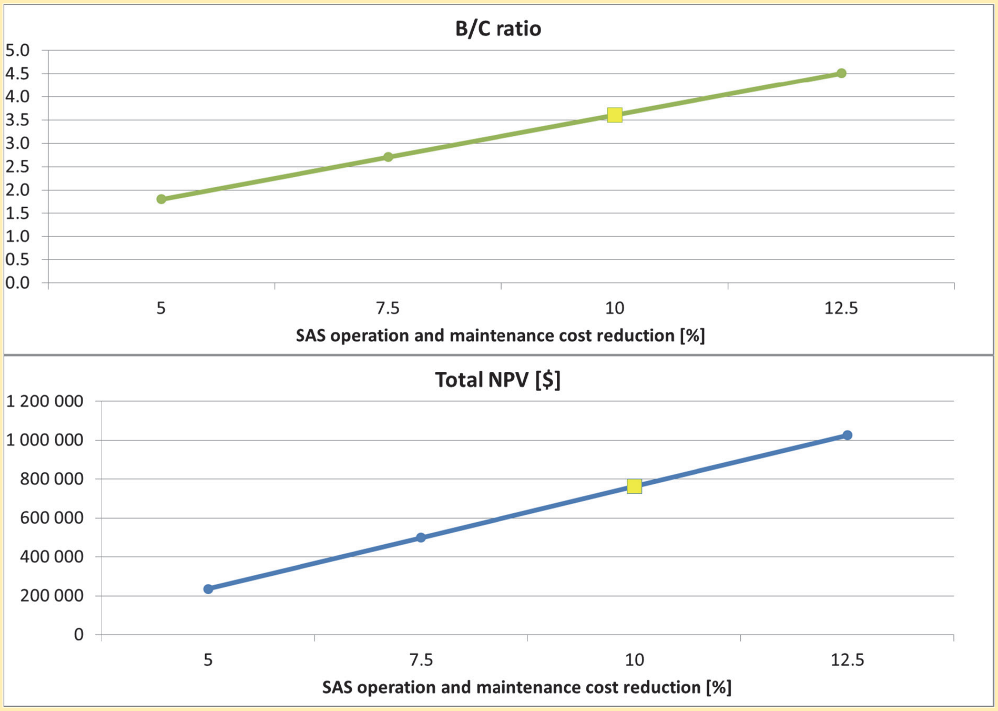
Source: Authors

FIGURE 99: DTCR SENSITIVITY ANALYSIS



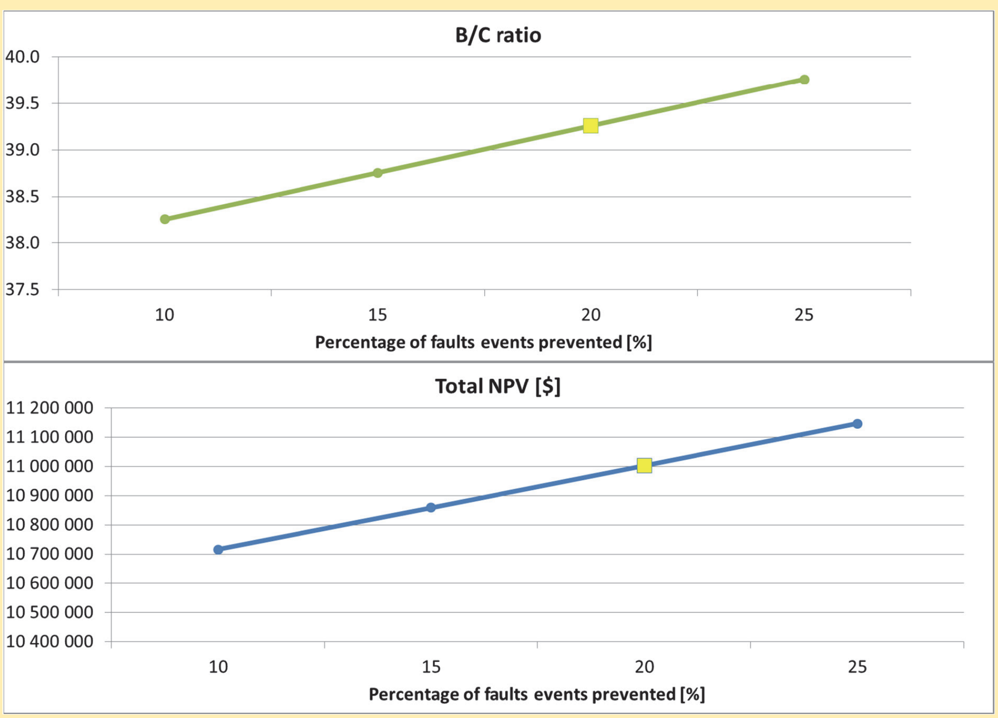
Source: Authors

FIGURE 100: GIS SENSITIVITY ANALYSIS



Source: Authors

FIGURE 101: POWER QUALITY MONITORING AND METERING DATA ACQUISITION SYSTEMS SENSITIVITY ANALYSIS



Source: Authors

I. Risk Analysis

I.1 Key Points Summary

In this chapter the risks analysis has been performed in order to collate all the key information for the final prioritization of the initiatives and the refinement of Smart Grid roadmap.

Towards this end, all the key parameters required to evaluate the risks are defined in terms of:

a. **Risk categories**;

b. **Risk impact**; and

c. **Risk likelihood**.

Based on these parameters a risk assessment has been carried out for all the Smart Grid initiatives, weighting the risk impact with the related risk likelihood and so measuring the chance of failure of each solution. In particular this analysis highlights those solutions that carry a greater probability of failure (like FLS and DGA) in terms of "**Time**", "**Stakeholders' actions**" and "**Investment uncertainty**".

Finally, the underlined risks cannot be fully eliminated, but they can be mitigated through the application of some ameliorating actions suggested in this chapter.

The identified risks, related mitigating actions together with the technical reasons (described in the technical analysis report) as well as the economic results of the Cost-Benefit Analysis (performed in the previous chapters) have together helped to decide the final prioritization of Smart Grid initiative carried out in chapter 'J'.

I.2 Definition of risks categories, scale and likelihood

The risk assessment process is an essential step before defining the final prioritization of the initiatives in the Smart Grid roadmap. As for all large-scale programs, the Vietnamese Smart Grid roadmap will face various risks that cannot be fully eliminated, but that can be mitigated through the systematic application of management policies, procedures and practices.

It is crucial to evaluate all the risks related to each Smart Grid initiative in order to "measure" the odds of success or failure.

The risk assessment process is comprised of different steps, which from the context awareness and risks categories definition leads to identifying a risk scale and likelihood thus leading to a risk assessment of the Smart Grid initiatives.

This paragraph 'I.2' aims to define all the relevant parameters for evaluating the risks. In particular it identifies:

a. **Risk categories**. It is crucial to understand all the possible risk sources and group them in an appropriate way;

b. **Risk impact scale**. It is fundamental to measure the impact of the risks on the Smart Grid roadmap and on return on the investment of each initiative;

c. **Risk likelihood scale**. It is fundamental to measure the odds of success and failure.

Having an understanding of the key elements that could impact on the Smart Grid roadmap is crucial to establishing the context,. in order to facilitate the risk assessment, the various sources of risk can be grouped into categories as follows:

a. **Time**. Both the starting time and the pace of installation of each Smart Grid initiative must be considered carefully. In some cases if the return of an investment is postponed the corresponding benefits may not cover the costs. This is even more apparent when the initiative postponed is an enabling technology for other stages of the roadmap.

b. **Stakeholders' actions**. The behavior, strategy and policies of the internal and external stakeholders will affect the roadmap implementation. In particular the level of commitment from the institutions and the extent to which their processes and attitudes hinder the progress of the roadmap will have to be considered.

c. **Investment uncertainty.** The CBA performed in the previous chapters has identified some indicators that define the uncertainty of the investment for each Smart Grid initiative. In particular these indicators are:

i. **EIRR**: A higher EIRR indicates a low risk investment. That is, EIRR shows by how much the discount rate or risk probabilities have to rise in order to eliminate the present value of this investment.

ii. **Sensitivity analysis results**: Sensitivity analysis involves recalculating project outcomes (NPV, B/C ratio) for different values of the major variables and combinations of variables. The risk of the project is considered high if a small change in a variable with respect to the baseline scenario causes a big change in the economic parameters thus making the project non-viable. On the contrary, if the project remains viable despite a big change in its main variables the risk is considered low.

Table 70 summarizes the possible risks source considered for each risk categories.

The various sources of risks under each category can have different levels of impact. So, before performing the risk assessment, it is helpful to assume a risk scale to evaluate the impact of the identified risk to the Smart Grid initiatives. Table 71 defines the risk impact scale that is used in "Risk assessment of Smart Grid initiatives" described in the next paragraph 'I.3'.

TABLE 70: RISK CATEGORIES

Risk category	Possible risks source considered
Time	• The delay to the implementation process of an initiative that directly and consistently affects the return on the investment. • The delay in the implementation process of an initiative that directly affects the success of the Smart Grid roadmap.
Stakeholders' actions	• The institutional level/process level capabilities and willingness to address risks. • The commitment from the authorities to implement the roadmap. • The deployment resource for a Smart Grid initiative is downsized. • Inefficient exploitation of a Smart Grid initiative.
Investment uncertainty	• **EIRR** determines the level of the investment uncertainty and so a low value implies a high implementation risk. • **Sensitivity** of a key parameter of a Smart Grid initiative can alter its benefits. A change in the project viability as a consequence of a small change in the parameter indicates a high implementation risk.

Source: Authors

TABLE 71: RISK IMPACT SCALE

Level number	Impact Level	Description
1	**Insignificant**	No real business impact - may have a low financial or time line impact but no change relative to baselines.
2	**Minor**	Inconvenient - no significant impact, can be immediately contained but no change relative to baselines.
3	**Moderate**	Medium to high impact - may have a medium financial or time line impact but no change relative to baselines.
4	**Major**	Extensive impact - especially to the business, high to major financial loss and a compelling need to change go live dates. Change relative to baselines.
5	**Catastrophic**	Huge impact - could result in the project being terminated with commensurate financial loss. Change relative to baselines.

Source: Authors

TABLE 72: RISK LIKELIHOOD SCALE

Level number	Likelihood level	Description
1	Rare	The risk may occur only in exceptional circumstances
2	Low	The risk could occur at some time
3	Moderate	The risk should occur at some time
4	High	The event will probably occur in most circumstances
5	Almost Certain	The event is definitely expected to occur in most circumstances

Source: Authors

To perform the risk assessment of each Smart Grid initiative it is important to weight the impact of each risk using a scale that indicates the probability of its occurrence. Therefore, each risk is characterized not only by the level of impact but also by the likelihood of it occurring. Table 72 defines the risk likelihood scale that is used in "Risk assessment of Smart Grid initiatives" descripted in the next paragraph 'I.3'.

I.3 Risk assessment of Smart Grid initiatives

In this paragraph the risk assessment is concluded and all the key information for the final prioritization of the initiatives is collated and used to refine the Smart Grid roadmap. For each Smart Grid initiative the possible risks are evaluated in terms of both likelihood and impact.

Table 73 summarizes all the risks that have been considered for each initiative:

a. The green cells indicate "**Time**" category risks;

b. The violet cells indicate "**Stakeholders' actions**" category risks;

c. The orange cells indicate "**Investment uncertainty**" category risks. The risks are reported as a variation with respect to the baseline scenario, which represents the best case scenario.

The increase in the discount rate with respect to the assumption made in the baseline scenario is an external risk for all the projects investigated. In fact, the discount rate adopted for the assessment of the economic viability of the initiatives can be influenced by many factors (inflation rate, default risk, interest rate, macroeconomic growth, exchange rate, etc.) and a variation of one of them can affect the predicted outcomes the cost-benefit analysis.

The risk likelihood of an increase in the discount rate is considered moderate while the impact of this event depends on the specific initiative and has been estimated using the EIRR (low value of this parameter equates to a high implementation risk).

In the next paragraphs (from 'I.3.1' to 'I.3.10') the specific risks of each initiative are investigated with an explanation for their characterization in terms of likelihood and impact.

I.3.1 Substation Automation System (SAS)

It is possible that there is a "Delay in the installation of new substations equipped with SAS" but even though the likelihood of this happening is quite high the risk of reduced benefits is low because the return on investment time is relatively short.

Further, the possibility of the "Initiative being downsized" is very low because the SAS project has already reached a high level of deployment in Vietnam. However, if this were to happen it would mean fewer substations installed with SAS and thus a smaller value for the reduction of EMS. Ultimately the reduction of EMS is directly proportional to the number of substations installed with SAS.

The "Decrease of Energy Not Served value" with respect to the baseline scenario has a medium financial impact as can be seen in the preceding sensitivity analysis (paragraph 'H.2'). ENS value per MWh could decrease by 30% without affecting the economic viability of the SAS implementation but would reduce the NPV and B/C ratio. The likelihood of this happening is considered moderate, as the value adopted in the reference scenario is a conservative estimate.

TABLE 73: SMART GRID APPLICATION RISK ASSESSMENT

Smart Grid Initiative	Risk	Likelihood	Impact
SAS	Delay in the installation of new substations equipped with SAS	Moderate (3)	Minor (2)
	Initiative downsized	Very low (1)	Major (4)
	Increase in the discount rate	Moderate (3)	Minor (2)
	Decrease of Energy Not Served value	Moderate (3)	Moderate (3)
	Decrease of average value of annually ENS reduction per substation equipped with SAS	Low (2)	Moderate (3)
WAMS	Delay in PMU installation	Moderate (3)	Minor (2)
	Delay in developing application based on WAMS	Moderate (3)	Major (4)
	Reduction in the number of installed PMUs	Moderate (3)	Minor (2)
	Inefficient development of applications based on WAMS data	Moderate (3)	Major (4)
	Increase in the discount rate	Moderate (3)	Insignificant (1)
	Decrease of Energy Not Served value	Moderate (3)	Minor (2)
	Decrease of the percentage of fault events prevented	Moderate (3)	Minor (2)
Lightning Location System	Delay in sensor installations	Moderate (3)	Minor (2)
	Delay in developing remote monitoring center	Moderate (3)	Major (4)
	Reduction in the number of installed sensors	Moderate (3)	Minor (2)
	Inefficient exploitation of the system in daily operation	Moderate (3)	Major (4)
	Increase in the discount rate	Moderate (3)	Insignificant (2)
	Decrease of Energy Not Served value	Moderate (3)	Minor (2)
	Decrease of the percentage of fault events prevented	Moderate (3)	Minor (2)
SVC	Delay in the installation process	Moderate (3)	Minor (2)
	Inappropriate choice of installation sites	Moderate (3)	Major (4)
	The selected sites are only temporarily adequate	Moderate (3)	Major (4)
	Increase in the discount rate	Moderate (3)	Major (4)
	Decrease of Energy Not Served value	Moderate (3)	Moderate (3)
	Decrease of the percentage of fault events prevented	Moderate (3)	Moderate (3)
HVDC	Delay in the installation process	Moderate (3)	Minor (2)
	Low power factor in operation of the HVDC link	Low (2)	Catastrophic (5)
	Increase in the discount rate	Moderate (3)	Insignificant (2)
	Decrease of power losses cost	Moderate (3)	Major (4)
FLS	Delay in the installation process	Moderate (3)	Minor (2)
	Initiative scope downsized	Low (2)	Major (4)
	Increase in the discount rate	Moderate (3)	Major (4)
	Decrease of outage time duration reduction	Moderate (3)	Catastrophic (5)
	Decrease of Energy Not Served value	Moderate (3)	Major (4)
	Decrease of percentage of lines with faults monitored with the FLS	Moderate (3)	Major (4)
DGA	Delay in the transformer installation process	Moderate (3)	Insignificant (1)
	Initiative scope downsized	Low (2)	Minor (2)
	Increase in the discount rate	Moderate (3)	Major (4)
	Decrease of average cost of a transformer fault	Moderate (3)	Catastrophic (5)
Dynamic Thermal Circuit Rating	Delay in the equipment installation process	Moderate (3)	Minor (2)
	Inefficient exploitation of the system in daily operation	Low (2)	Major (4)
	Increase in the discount rate	Moderate (3)	Insignificant (1)
	Decrease of the number of lines with deferred reconductoring	Moderate (3)	Minor (2)
	Decrease of number of years of deferred investment	Moderate (3)	Minor (2)
GIS	Delay in the implementation process	Low (2)	Minor (2)
	Exploitation of the initiative in a limited number of contexts	Low (2)	Moderate (3)
	Increase in the discount rate	Moderate (3)	Minor (2)
	Decrease of operation and maintenance cost savings for SAS application	Moderate (3)	Minor (2)
Power quality monitoring and Metering Data Acquisition Systems	Delay in the implementation process	Moderate (3)	Minor (2)
	No proper consideration of the regulatory implications	Moderate (3)	Major (4)
	Increase in the discount rate	Moderate (3)	Insignificant (1)
	Decrease of Energy Not Served value	Moderate (3)	Minor (2)
	Decrease of the percentage of fault events prevented	Moderate (3)	Minor (2)

Source: Authors

The "Decrease of average value of annual ENS reduction per substation equipped with SAS" with respect to the baseline scenario has a medium financial impact. The sensitivity analysis (paragraph 'H.3') demonstrates that NPV remains positive even though the ENS reduction per substation falls to 50% of the best estimation.

I.3.2 Wide Area Monitoring System (WAMS)

Regarding WAMS, the "**Time**" risks can be derived from both "Delay in PMU installation" and from "Delay in developing applications based on WAMS" and they can be considered equally likely. While the first cause a reduction in the observability of the network the second one causes a consistent reduction in the benefits and thus has a higher impact. Without a complete and effective development of monitoring applications based on PMU data no benefits will be achieved.

It is worth pointing out that in the table under "**Stakeholders' actions**" risks, a "An inefficient development of applications based on WAMS" carries far more risk to the success of the project than does a "Reduction in the number of installed PMUs".

The "Decrease of Energy Not Served value" with respect to the baseline scenario has no significant financial impact as can be seen in the sensitivity analysis (paragraph 'H.2'). ENS value per MWh could decrease by 30% without affecting the economic viability of the WAMS implementation but would reduce the NPV and B/C ratio. The likelihood of this event is moderate as the value used in the reference scenario is a conservative estimation.

The "Decrease of the percentage of fault events prevented" with respect to the baseline scenario has no significant financial impact as can be seen in the sensitivity analysis (paragraph 'H.4'). The effect of a 50% reduction of the avoided faults is just a 10% decrease in the NPV which in any case remains strongly positive. The probability of this event is moderate as the value adopted in the reference scenario is a realistic estimation.

I.3.3 Lightning Location System (LLS)

As with WAMS, the "**Time**" risks can be derived from both "Delay in sensors installation" and from "Delay in developing remote monitoring center" and they are both equally likely. The real added value of LLS (as for WAMS) is the availability of the data in a remote control center so the second type of delay has a higher impact. Without the full development of a monitoring center for collecting and processing data no benefits will be achieved.

It is worth pointing out that "**Stakeholders' actions**" risks, a "Weak exploitation of the system in daily operation" carries far more risk to the success of the project than does a "Reduction in the number of installed sensors".

The "Decrease of Energy Not Served Value" with respect to the baseline scenario has no significant financial impact as can be seen from the sensitivity analysis (paragraph 'H.2'). ENS value per MWh could decrease by 30% without affecting the economic viability of the LLS implementation but would slightly reduce NPV and B/C ratio. The likelihood of this is moderate as the value adopted in the reference scenario is a conservative estimation.

The "Decrease of the percentage of fault events prevented" with respect to the baseline scenario has no significant financial impact. As can be seen from the sensitivity analysis (paragraph 'H.5') a 60% reduction of the avoided faults would result in a 15% decrease in the NPV, which would still remain positive. The probability of this event is moderate.

I.3.4 Static Var Compensator (SVC)

The process of selecting the right sites for the installation of the SVCs could delay the entire implementation process. If this "**Time**" risk is less than 2 years, the delay will have a minor impact as it only delays the return on investment. However, the "**Stakeholders' actions**" risks are more critical. The "No proper choice of the installation sites" in conjunction with "The selected sites are only temporarily adequate" could completely compromise the investment in such equipment.

The "Decrease of Energy Not Served Value" with respect to the baseline scenario has a medium financial impact as can be seen from the sensitivity analysis (paragraph 'H.2'). ENS value per MWh could decrease by 30% without affecting the economic viability of the SVC implementation but would reduce NPV and B/C ratio. The likelihood of this event is moderate as the value adopted in the reference scenario is a conservative estimation.

The "Decrease of the percentage of fault events prevented" with respect to the baseline scenario has a medium-high financial impact as can be seen from the sensitivity analysis (paragraph 'H.6'). A 50% decrease in the avoided faults would cause a negative NPV and threaten the economic viability of the project. The likelihood of this event is moderate as the value adopted in the reference scenario is a conservative estimation.

I.3.5 High Voltage Direct Current (HVDC) technology

Similarly to SVC, the site selection process for the installation of these devices could delay the project significantly. The cost-benefit analysis performed on HVDC technology demonstrates that a delay in the installation will in turn delay the return on investment. This is classified a minor risk for the implementation of this technology.

It is worth noting that once a HVDC link is in place it is important to the return on investment that it does not suffer from a "Low power factor in operation on the HVDC link" as this will have a detrimental impact on the benefits of the initiative.

The "Decrease of power losses cost" with respect to the baseline scenario has a significant impact and has been assessed as a major to high risk of financial loss as can be seen from the sensitivity analysis (paragraph 'H.7'). The impact of a 20% reduction in the energy cost will represent a financial loss to the project (i.e. a negative NPV and a B/C ratio less than one). The probability of this event has been considered moderate as the value adopted in the reference scenario is a realistic estimation.

I.3.6 Fault Locator System (FLS)

A delay in the FLS installation process has a minor impact because it only delays the return on the investment. However, a reduction of the lines protected ("Initiative downsized") proportionally decreases the ability to protect the critical lines with FLS devices and consequently reduces the benefit of this initiative. While the impact is significant, the risk that the FLS initiative is downsized is quite low because NPT has already decided to equip about 70 lines with these devices.

The "Decrease of Energy Not Served value" with respect to the baseline scenario has an extensive impact assessed as major to high risk of financial loss. As can be seen from the sensitivity analysis (paragraph 'H.2') NPV becomes negative if the ENS value is 15% lower than the baseline scenario.

The "Decrease of outage time duration reduction" with respect to the baseline scenario has a huge impact and could result in the project not being financially viable as can be seen from the sensitivity analysis (paragraph 'H.8'). A 10% decrease in the reduction of outage time duration relative to the baseline compromises the viability of the initiative (i.e. causes a negative NPV and a B/C ratio less than one). The likelihood of this event is moderate as the value adopted in the baseline scenario is a conservative estimation.

The "Decrease of percentage of lines with faults monitored with the FLS" with respect to the baseline scenario has an extensive impact assessed as major to high risk of financial loss. The sensitivity analysis (paragraph 'H.8') demonstrates that NPV becomes negative when the number of lines with faults equipped with a FLS decreases by 10% when compared with the baseline.

I.3.7 On-line Dissolved Gas-in-oil Analysis (DGA)

In this case the installation of the DGA monitoring device is connected with the installation of a new transformer, so both benefits and costs will be equally delayed. The impact of such a risk can be considered negligible.

Similarly, if the initiative is downsized by a decision not to equip a significant number of the new transformers with DGA monitoring devices, the initiative will continue to be beneficial. The overall benefit of the initiative is a simple sum of the single benefits obtained from each transformer protected.

The "Decrease of the average cost of a transformer fault" with respect to the baseline scenario has a huge impact and could result in the project not being viable as can be seen from the sensitivity analysis (paragraph 'H.9'). The impact of a 10% reduction in the cost of a transformer fault will mean a financial loss for the initiative as a whole (i.e. a negative NPV and a B/C ratio less than one). The probability of this event is moderate as the value adopted in the reference scenario is a realistic estimation.

I.3.8 Dynamic Thermal Circuit Rating (DTCR)

The time window for a return on investment in a DTCR solution is quite large so any delays in the installation process will not risk the benefits. On the other hand, an "Inefficient exploitation of the system in daily operation" will utterly compromise the investment in this solution. However, a well-designed project for the development of dynamic rating will do much to mitigate if not entirely preclude this risk.

The "Decrease of the number of lines with deferred reconductoring" with respect to the baseline scenario has a no significant impact as can be seen in the sensitivity analysis (paragraph 'H.10'). The number of lines could be reduced by 50% (in this case two instead of four) without affecting the economic viability of the DTCR implementation but will result in a slightly lower NPV and B/C ratio. The likelihood of this event is moderate as the value adopted in the reference scenario is a realistic estimation.

The "Decrease of number of years of deferred investment" with respect to the baseline scenario has no significant financial impact. The sensitivity analysis (paragraph 'H.10') indicates that NPV remains high and positive even though the number of years of deferred investment is assumed to be three instead of five (best case scenario).

I.3.9 Geographic Information Systems (GIS)

Delaying the implementation of this solution does not present a particular risk to the Smart Grid initiative. However, it provides vital geographical data that can be exploited and shared by a large number of applications (SAS, WAMS, etc.). Thus delays or even "Exploitation of the initiative in a few contexts" will reduce the potential benefits of this initiative.

The "Decrease of operation and maintenance cost savings for SAS application" with respect to the baseline scenario has a no significant financial impact. The sensitivity analysis (paragraph 'H.11') shows that while a 50% reduction in the SAS O&M savings will decrease the NPV by 70%, it will still remain positive. The likelihood of this event is moderate.

I.3.10 Power quality monitoring and Metering Data Acquisition Systems

Again, a delay in the implementation of these two applications does not have any particular repercussions. However, if "No proper consideration of the regulatory implications" occurs, the financial investment could be lost. As stated in the technical report, for the successful exploitation of these two initiatives it is vital that a suitable and clear regulatory policy focused on the relationship with the electricity generation function be developed in order to ensure maximum synergy under critical conditions.

The "Decrease of Energy Not Served value" with respect to the baseline scenario has no significant financial impact as can be seen from the sensitivity analysis (paragraph 'H.2'). ENS value per MWh may decrease by 30% without affecting the economic viability of the implementation but will result in a slightly lowered NPV and B/C ratio. The likelihood of this event is moderate as the value adopted in the reference scenario is a conservative estimation.

The "Decrease of the percentage of fault events prevented" with respect to the baseline scenario has a no significant financial impact as can be seen from the sensitivity analysis (paragraph 'H.12'). The effect of a 50% reduction of the faults avoided is just a 5% decrease in the NPV, which will still remain positive. The probability of this event is moderate as the value adopted in the reference scenario is a realistic estimation.

I.4 Risk Map

The impact of each risk can be multiplied by a weighting value to calculate its likelihood. The risks associated with each initiative can be compared based on assuming a high-risk scenario for each.

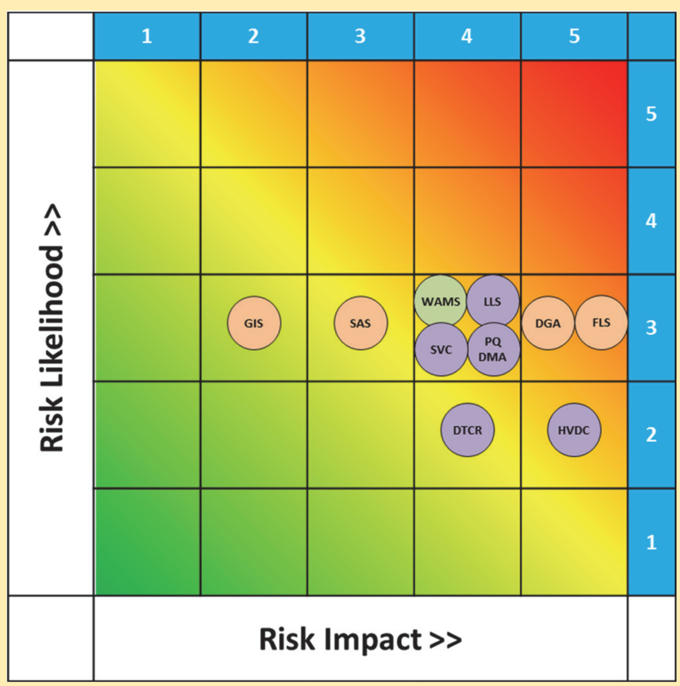
This comparison is graphically depicted in Figure 102 below. Each Smart Grid initiative has been positioned on a graph where the abscissa (x axis) is the risk impact while the ordinate (y axis) maps the risk likelihood. The color shade of each Smart Grid initiative identifies the risk category where:

a. Green stands for the "**Time**" category risk;

b. Violet stands the "**Stakeholders' actions**" category risk;

c. Orange stands for the "**Investment uncertainty**" category risk.

FIGURE 102: RISK MAP



Source: Authors

I.5 Risk mitigation actions

While the risks identified for each initiative cannot be fully eliminated, they can be mitigated by appropriate actions and procedures as suggested in Table 74 This table lists some recommendations for the various risk categories (green for "Time", violet for "Stakeholders' actions" and orange for "Investment uncertainty").

TABLE 74: RISK MITIGATION ACTIONS

Smart Grid Initiative	Mitigation action
SAS	Link the final commissioning of new substations with the complete commissioning of their SAS equipment.
	Manage the gap between the roadmap and real installation pace.
	Streamline the SAS automation installation process to target the most critical areas first. Monitor the performance of the already implemented SAS for a better estimation of the ENS saved and a reduction of the investment uncertainty.
WAMS	Expedite the development of the remote control center.
	Focus investments on developing applications based on WAMS data.
	Streamline the Phase Measurement Unit installation process to target the most critical lines. Monitor the performance of the installed PMUs for a better estimation of the faults that can be avoided and a reduction of the investment uncertainty.
Lightning Location System	Expedite the development of the remote control center.
	Focus investments on developing applications fed by LLS data and carry out adequate training for the control room operators to exploit LLS information.
	Optimize the positioning of the sensors in order to cover the whole network.
SVC	Engage with the planning department to choose optimal installation sites.
	Re-locatable SVCs can easily solve the problem of site selections that are either not the best fit for purpose or those sites that are only temporarily fit for purpose.
	Develop a planning activity for the SVC initiative in order to improve the reactive compensation starting with the most critical areas. Use the first implementations for data collection and reduction of investment uncertainty.
HVDC	Engage with the planning department to choose optimal installation sites.
	Develop a proper system operation strategy to fully exploit the HVDC links.
	Perform electricity market studies for the medium and long term in order to better estimate the cost of energy and investigate potential profitable connections with foreign countries.
FLS	Expedite the installation for the most critical lines.
	Manage the gap between the roadmap and real installation pace.
	Optimise the planning activities in order to implement the FLS on those lines with the highest maintenance cost. Monitor the already implemented FLS's for a better estimation of the average reduction outage time duration that is possible with this initiative.
DGA	Align the final commissioning of new transformers and their DGA equipment.
	Manage the gap between the roadmap and real installation pace.
	Optimize the planning activities in order to implement the DGA on those transformers with the highest cost of repair and those with the highest fault probability. Monitor the already implemented DGA's for a better estimation of the benefits that can be obtained with this initiative.
Dynamic Thermal Circuit Rating	Expedite the installation on the most critical lines.
	Develop a proper system operation strategy to full exploit the dynamic rating initiative.
	Develop a planning activity for the DTCR initiative in order to improve the transfer capacity of the lines starting with the most critical areas.
GIS	Place GIS on the critical path for the installation of those applications that will benefit from it.
	Evaluate the added value of GIS functionality for the largest number of applications.
	Develop an effective software application and user interface in order to maximize the benefit of the GIS initiative in terms of O&M reduction.
Power quality monitoring and Metering Data Acquisition Systems	Expedite the installation on the most critical areas.
	Develop a clear regulatory policy focused on the relationship with the electricity generation function to ensure maximum synergy under critical conditions.
	Develop a planning activity for the initiative in order to reduce the unserved energy starting with the most critical areas.

Source: Authors

J. Final Prioritization

J.1 Key Points Summary

The aim of this chapter is to perform the final prioritization of all the Smart Grid initiatives and to position them on a timeline, setting the best starting point for the solutions and proposing suitable elapsed times for their development.

This prioritization is a refinement of the Vietnamese Smart Grid roadmap and includes a phased implementation plan. This analysis factored in the following for each Smart Grid initiative:

a. The technical reasons described in technical analysis report;

b. The economic results of the Cost-Benefit Analysis performed in the previous chapters (from 'D' to 'H'); and

c. The risks and related mitigation actions investigated in the previous chapter.

As in the technical analysis report three different time scales are considered in the development of the initiatives:

a. Short term (within next 5 years);

b. Medium term (within next 10 years); and

c. Long term (within next 15 years).

This prioritization process has assigned the following:

a. Geographic Information Systems positioned in the short term;

b. Dynamic Thermal Circuit Rating positioned in the short term;

c. Lightning Location System positioned in the short term;

d. Fault Locator System with recommended preliminary activities and their finalization in the short term;

e. Static Var Compensator with some preliminary activities in the short term with finalization of the expected installed capacity at the start of the medium term;

f. Wide Area Monitoring System starts in the short term while the complete rollout concludes in the medium term. The prioritization of the main lines and areas are in the short term;

g. Substation Automation System, including remote control centers building/upgrade, already started in the short term will continue with the rollout until completion in the medium term;

h. Power quality monitoring system and Metering Data Acquisition System start in the short term with the full rollout expected in the medium term;

i. High Voltage Direct Current technology with the pre-requisite preliminary studies and activities in the short term and the finalization of the medium term; and

j. On-line-Dissolved Gas-in-oil Analysis, already started in the short term, will be completed in the long term.

J.2 Smart Grid initiatives time positioning

In order to refine the final prioritization of the Smart Grid initiatives the timeline positioning suggested in the technical analysis has been selected as a starting point. The positioning of the various initiatives has factored in the economic results of the Cost-Benefit Analysis and the previously assessed risks.

In particular:

a. **The positioning of an application is confirmed** at its current point on the timeline if it is not contradicted by its economic and risk indicators;

b. **The positioning of an application is brought forward** from its current point on the timeline if its economic and risk indicators are compelling; and

c. **The positioning of an application is postponed** from its current point on the timeline if its economic and risk indicators are unfavorable.

Based on these premises the following applications have been confirmed for implementation in the short-term:

a. **Wide Area Monitoring System**. This application is recommended to begin in the short term with the complete rollout being concluded in the medium term. The prioritization of the main lines and areas are positioned in the short term. As stated in the technical analysis report WAMS is a solution that "enables" some of the others (e.g. Dynamic Thermal Circuit Rating) and will help solve a large number of issues (e.g. voltage and transient stability, defense plan deficiencies, etc.); so its development must start as soon as possible. Furthermore, WAMS's economic indicators are very positive (EIRR: 204% and B/C ratio: 17.82) and the initiative does not present unconquerable risks if the WAMS based applications are properly developed. The implementation activity is comprised of:

   i. Development of a remote control center;

   ii. Development of a strategy for the location of PMUs;

   iii. Installation and cabling of PMUs;

   iv. Development and implementation of WAMS based applications; and

   v. Integration of information and results obtained from WAMS based applications and daily systems operation.

b. **Substation Automation System**. This is a NPT project that has already reached a significant level of development. The initiative, which includes the building/upgrading of remote control centers, has already started and is positioned, by default, in the short term but its complete rollout will not conclude until the medium term. The economic indicators are positive and the assessed risks can be successfully mitigated with an efficient substation commissioning policy and management of the gap between the roadmap and real installation pace. The implementation activity includes the installation and the commissioning of new substations equipped with SAS.

c. **Lightning Location System.** This initiative has been positioned in the short term. The technical analysis had considered this as a short-term solution due to the criticality of the lightning problem in Vietnam. The intelligence of the system is supplied by the location system and not the arresters (which are dumb devices). The economic indicators (EIRR: 164% and B/C ratio: 6.89) are compelling reasons to investment in this solution. All the risks associated with this initiative can be mitigated by focusing the investments on developing applications fed by LLS data and carrying out commensurate training for the control room operators to exploit LLS information. As stated in the technical analysis report, the basic implementation phases are:

   i. The evaluation of all the available technologies with respect to the specific needs of all the transmission utility functions that could benefit from such a system;

   ii. The evaluation of the number of sensors needed to cover the country with homogeneous and high detection performance, event discrimination, location accuracy and 24/7 availability;

   iii. The evaluation of the orography and consequently the identification of the ideal locations for the sensors (taking account of factors like electromagnetic noise, structural shields, physical security, terrain, telecommunication links, etc.);

   iv. Obtaining contractually binding agreements with local site owners wherever necessary;

   v. The execution of all civil and electrical works at the identified sites including power and telecommunications cabling if needed;

   vi. The implementation of an Operational Center provided with specific power and telecommunication schematics and a server for data analysis where all sensor data will be received, processed and stored;

   vii. The fine tuning of LLS (using the most immediately available data), implementing site corrections of detection parameters and thresholds where needed; and

   viii. The assignment of dedicated and properly trained staff.

d. **Power quality monitoring system and Metering Data Acquisition System.** These initiatives are prioritized in the short term but their complete rollout will not conclude until the medium term. Both these initiatives have been positioned in the short-term because their total cost (CAPEX: $301,500 and OPEX: $97,200) is amongst the lowest of all the initiatives while the economic indicators are the most compelling (EIRR: 797%

and B/C ratio: 39.26). In order to mitigate the assessed risks before beginning the deployment of these initiatives it is important to carefully consider all the regulatory aspects. The implementation activity is basically comprised of:

i. Careful analysis of all the regulatory aspects;

ii. Development of a remote control center;

iii. Development of a strategy for the location of devices;

iv. Installation and cabling of devices; and

v. Implementation of software tools for processing data:

e. **Geographic Information Systems.** This is positioned in the short term. As stated in the technical analysis, the prior development of other systems like SAS or WAMS will be important to enable the implementation of this solution which is likely to support the largest number of applications and delivering significant benefits to the enterprise. Given that the total cost (CAPEX: $175,000 and OPEX: $262,500) is much lower than for most of the other systems and the economic indicators are positive (EIRR: 48% and B/C ratio: 3.61) it makes sound economic and technical sense to implement this system in the short term. Further, no particular risks have been highlighted. The implementation activity is basically comprised of:

i. Careful selection of all the applications that would benefit from this initiative;

ii. Development of procedures and strategies to store and share GIS data; and

iii. Implementation of software tools for processing and displaying data.

f. **Dynamic Thermal Circuit Rating.** This initiative has been positioned in the short term. The technical analysis had originally positioned this initiative in the long term on the basis that it would be better to wait for the current rapid growth rate of the transmission network to stabilize in order to leverage this application on a large scale. However, since the CBA has revealed that its economic indicators are extremely positive (EIRR: "All positive cash flows" and the B/C ratio: 35.11), it would make both technical and financial sense to implement this technology in the short term. The related risks can be easily mitigated by developing a rigorous system operation strategy that fully exploits the dynamic rating initiative. The implementation activity is basically comprised of:

i. Careful selection of the lines to be monitored;

ii. Choice of the monitoring devices;

iii. Development of algorithms and procedures for real-time temperature estimation; and

iv. Integration of information and results obtained from Dynamic Thermal Circuit Rating and daily system operations.

g. **Static Var Compensator.** Some preliminary activities are required to be performed in the short term while the roll-out of the total capability has been positioned at the beginning of the medium term. Such preliminary activity is highlighted in the final time positioning of the Smart Grid initiatives. Further, the risk analysis has revealed that as Vietnam's power network is growing rapidly it would significantly complicate the choice of the locations of SVC devices. To mitigate such risks relocatable SVCs have been suggested which will allow the flexibility of temporary installations while retaining the investment despite future growth. Even though the total cost is quite high (CAPEX: $31,500,000 and OPEX: $1,255,500) the economic indicators are good (EIRR: 14% and B/C ratio: 1.21) this investment makes good economic sense. Furthermore, the SVC initiative achieves significant benefits both in terms of integration of renewable energy generation and in terms of blackout prevention. Moreover, the criticality of the voltage stability issues in the Vietnamese [19] transmission network argues against delaying this measure for too long because it may jeopardize system security and availability. The plan to start its full implementation in the latter part of the short-term is likely the right choice as it will allow a suitable time for the detailed feasibility study phase. Therefore, the already planned devices can be installed but the full deployment of the initiative has to be positioned for the mid-term.

h. **Fault Locator System**. This initiative is positioned in the short-term. The economic indicators are lower than for other applications (EIRR: 13% and B/C ratio: 1.17) and the investment is quite high (CAPEX: $8,400,000). Also the risk assessment has highlighted that the "Investment uncertainty" has the highest value for this initiative. On the other hand, the NPT project is already underway and is quite independent from all the other initiatives. Therefore, the recommendation is to evaluate the real benefits of this technology on a small number of lines and then decide if it is worth deploying across the estate. For this reason only a pilot program for FLS benefits evaluation has been positioned in the short term. If in the next few years the cost of this technology decreases its current positioning can be reconsidered and, if required, brought forward. Finally, the implementation activity is basically comprised of:

i. Careful selection of the lines to be monitored;

ii. Installation and wiring of the devices; and

iii. Development of algorithms and procedure for the exploitation of FLS data.

i. **On-line Dissolved Gas-in-oil Analysis**. CBA results show that the investment is less attractive in economic terms than other initiative (EIRR: 12% and B/C ratio: 1.13) and the total cost is quite high (CAPEX: $77,592,000 and OPEX: $3,343,245). But even if the high cost of monitoring devices would make this solution a high-risk economic strategy, it is worth to consider the average lifetime of this type of transformers (about 25 years) and to start investing in this technology in the short term. The transformers' fault risk in fact is not positioned in the near future but it is widespread in all their lifetime, which is longer that the time horizon considered for the investment. As described in the technical analysis (see Report 1, paragraph 'F.11'), it is fundamental to start monitoring transformers as soon as possible in order to effectively use the stored data for an accurate diagnostic in the future (15-20 years) on aged transformers, and so fully exploit DGA technology. Therefore the benefits of this initiative are achievable only if the device installation starts in the short term.

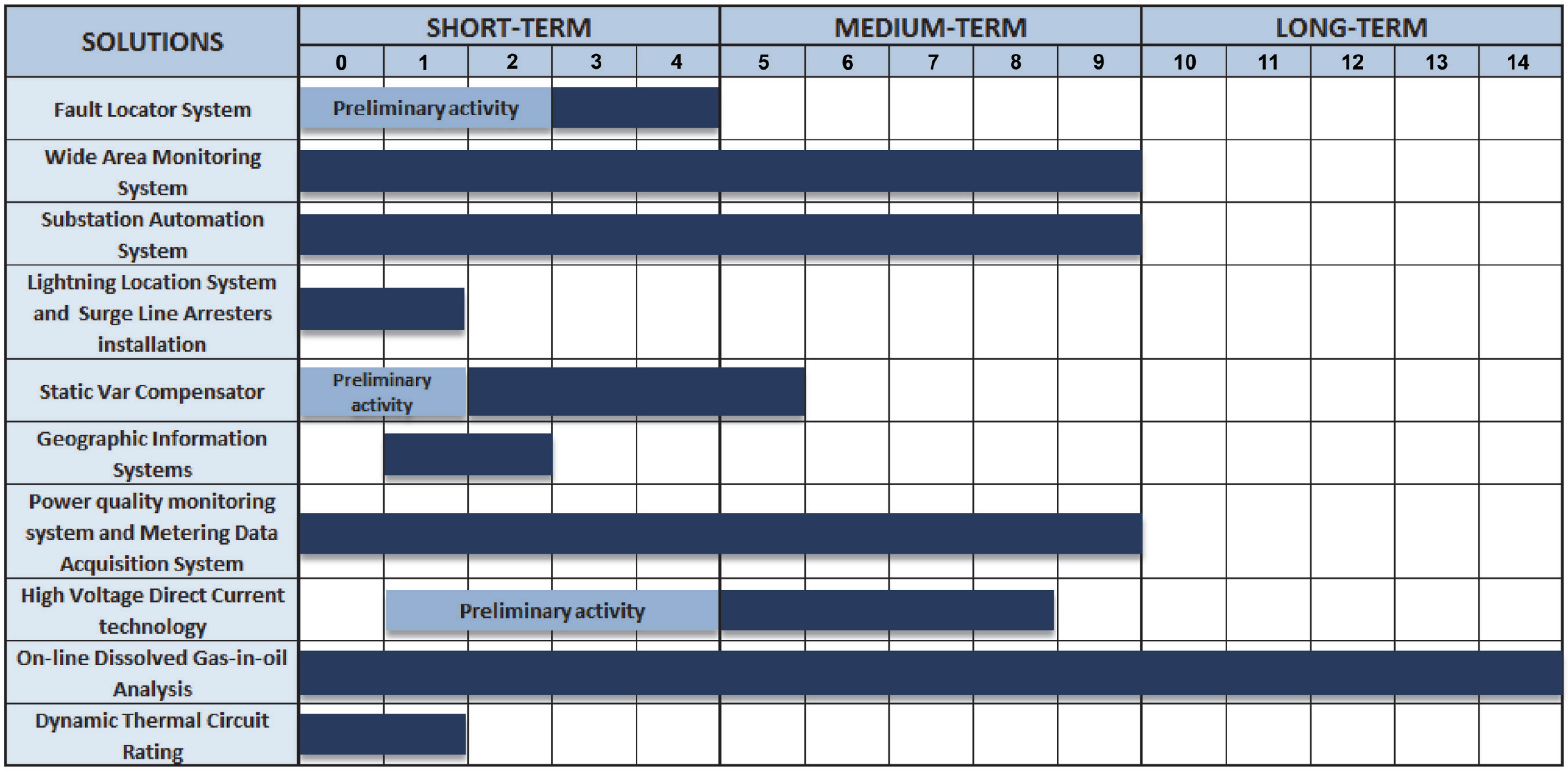
While in the medium-term are positioned:

a. **High Voltage Direct Current technology**. In order to assess the economic feasibility of the HVDC technology, the incremental costs of a new 800 km DC link compared with the cost of an AC 500 kV solution have been estimated. It has been assumed that the original planning for this installation only considered the technical benefits of the AC line rather than of the strategic benefits of the line itself to the wider network. This initiative requires preliminary studies and activities that should be conducted in the short term, while the implementation, if considered feasible following the findings of the study, should be positioned in the medium term. However, at the outset it can be safely assumed that the economic indicators are good with regard to the technology application per se if not the line itself. In fact, even if the total incremental costs are very high (CAPEX: -$16,800,000 and OPEX: $118,098,000), the EIRR has "All positive cash flows" the B/C ratio is 1.56. The economic indicators in fact do not consider several other strategic and technical benefits that if included would likely make a very strong case for the development of HVDC technology in Vietnam. On balance it is worth planning the development of this technology because it could prove useful for both interconnections with neighboring countries [19] and for long links (e.g. 500kV link with lengths greater than 700km) connecting the Northern and Southern parts of Vietnam. Furthermore, the HVDC technology is perhaps the best Smart Grid initiative in terms of integrating with new variable renewable generation. In fact the increased transfer capacity and active power control are fundamental benefits which would enable the installation of wind or solar power plants carrying the variable generated energy to the load areas and balancing the natural fluctuation of renewables. The real implementation of HVDC is reliable only in the medium term since this initiative requires quite a long preliminary feasibility study probably lasting about 4 years. Such preliminary activity is highlighted in the final time positioning of the Smart Grid initiatives. After this study phase the real implementation activity (comprised of the construction of the HDVC line/s) can start, which typically last, based on the consultant's experience, about 4 years.

The positioning of an initiative at a particular point on the timeline implies a starting point. It happens that the implementation process of some solutions will extend for 5 years or more. For example the SAS development process is already underway and it is considered a short-term initiative, although the complete installation will not be concluded for at least ten years. Equally the full implementation of WAMS, Power quality monitoring system and Metering Data Acquisition System, which are closely linked to the installations of new substations, will be completed in the same ten-year time interval.

Figure 103 shows the final timeline positioning of the Smart Grid initiatives and provides the phased implementation plan for the Vietnamese roadmap.

FIGURE 103: FINAL TIME POSITIONING OF SMART GRID INITIATIVES



Source: Authors

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ENDNOTES

1. According to the e-mail from NPT received on May 5th, 2015 and meeting with NLDC held on April 21st, 2015.

2. Smart Metering and Smart Grid Strategy for the Kingdom of Saudi Arabia.

3. The loss factor is the ratio of average power loss for a year to the loss at rated power during the same period.

4. The amount of equivalent hours is the number of hours per year which the rated power would have to continue to give the same total energy loss as that given by the variable load throughout the year.

5. Each Vietnamese costumer suffers an average of interruptions of 4,461 minute per years according EVN in his presentation "EVN Smart Grid Plan" from November 2013 [20].

6. The SAS cost just includes automation not the substation itself.

3

Volume 3: Regulatory and Performance Monitoring

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A. Acronym List

AMI	Advanced Metering Infrastructure
CAPEX	Capital Expenditure
CBA	Cost Benefit Analysis
COS	Cost-of-service regulation
DGA	Dissolved Gas-in-oil Analysis
DGE	Directorate General of Energy
DLR	Dynamic Line Rating
DMS	Distribution Management System
EIRR	Economic Internal Rate of Return
EMS	Energy Management System
ENS	Energy Not Served
EPRI	Electric Power Research Institute
ERAV	Electricity Regulatory Authority of Vietnam
EVN	Electricity of Viet Nam
FLS	Fault Locator System
GIS	Geographic Information System
HVDC	High Voltage Direct Current
IE	Institute of Energy
IRENA	International Renewable Energy Agency
JRC	Joint Research Center
KPI	Key Performance Indicator
LLS	Line Locator System
LSA	Line Surge Arrester
MOIP	Ministry of Industry and Trade
MP VII	Power Master Plan VII
NASPI	North American SynchroPhasor Initiative
NERC	North American Electric Reliability Corporation
NLDC	National Load Dispatch Centre
NPT	National Power Transmission Corporation
OPEX	Operational Expenditure
PMU	Phase Measurement Unit
PQ	Power Quality
RACI	Matrix that map the roles and responsibilities (Responsible, Accountable, Consulted and Informed)
ROR	Rate-of-return regulation
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAS	Substation Automation System
SCADA	Supervisory Control And Data Acquisition
SO	System Operator
SVC	Static Var Compensator
TLC	Telecommunication
TLSA	Transmission Line Surge Arrester
TO	Transmission Owner
TNO	Transmission Network Operator
TSO	Transmission System Operator
VCGM	Vietnam Competitive Generation Market
VCRM	Vietnam Competitive Retail Market
VCWM	Vietnam Competitive Wholesale Market
VoLL	Value of Lost Load
WAMS	Wide Area Monitoring System

B. Summary of Regulatory and Performance Monitoring

This document presents the Regulatory Performance Monitoring of the Smart Grid Program, and a strategy for its implementation.

Originally, the Smart Grid initiatives were tailored to fit the specific needs of Vietnam, taking account of not only the best international practices and experiences, but also the current Vietnamese operational problems and the status of their Smart Grid projects. During this analysis, some key areas or "pillars" were identified for implementation in order to increase the level of security and reliability of the Vietnamese power system.

The initial task performed was the prioritization of all the Smart Grid initiatives relevant to the Vietnam power sector according to a set of technical criteria that were identified as part of the Technical Analysis. The technical analysis identified the Smart Grid initiatives appropriate for Vietnam as discussed in 'Report 1 Chapter F'. These solutions were initially positioned on a technology-focused timeline.

The second task conducted was a Cost-Benefit analysis aimed at identifying the costs and benefits of each proposed Smart Grid initiative. This process also evaluated their economic parameters in order to understand the real added value of each initiative. This analysis helped to identify the most suitable solutions and repositioned them in the timeline according to these results.

Three different time horizons were considered for the development of the various applications:

a. Short term (within next 5 years);

b. Medium term (within next 10 years); and

c. Long term (within next 15 years).

In the light of this prioritization and taking account of the results from the economic analysis the applications were ordered according to their benefit-cost ratio. Those that should start in the short term are given below:

a. Dynamic Thermal Circuit Rating;

b. Power Quality Monitoring System and Metering Data Acquisition System;

c. Wide Area Monitoring System;

d. Lightning Location System;

e. Geographic Information Systems;

f. Substation Automation System;

g. Static Var Compensator;

h. Fault Locator System; and

i. On-line-Dissolved Gas-in-oil Analysis.

The following is achievable in the medium-term:

a. High Voltage Direct Current technology.

For the long-term no new initiatives have been planned, but the completion of ones already undertaken in short/medium-term is expected.

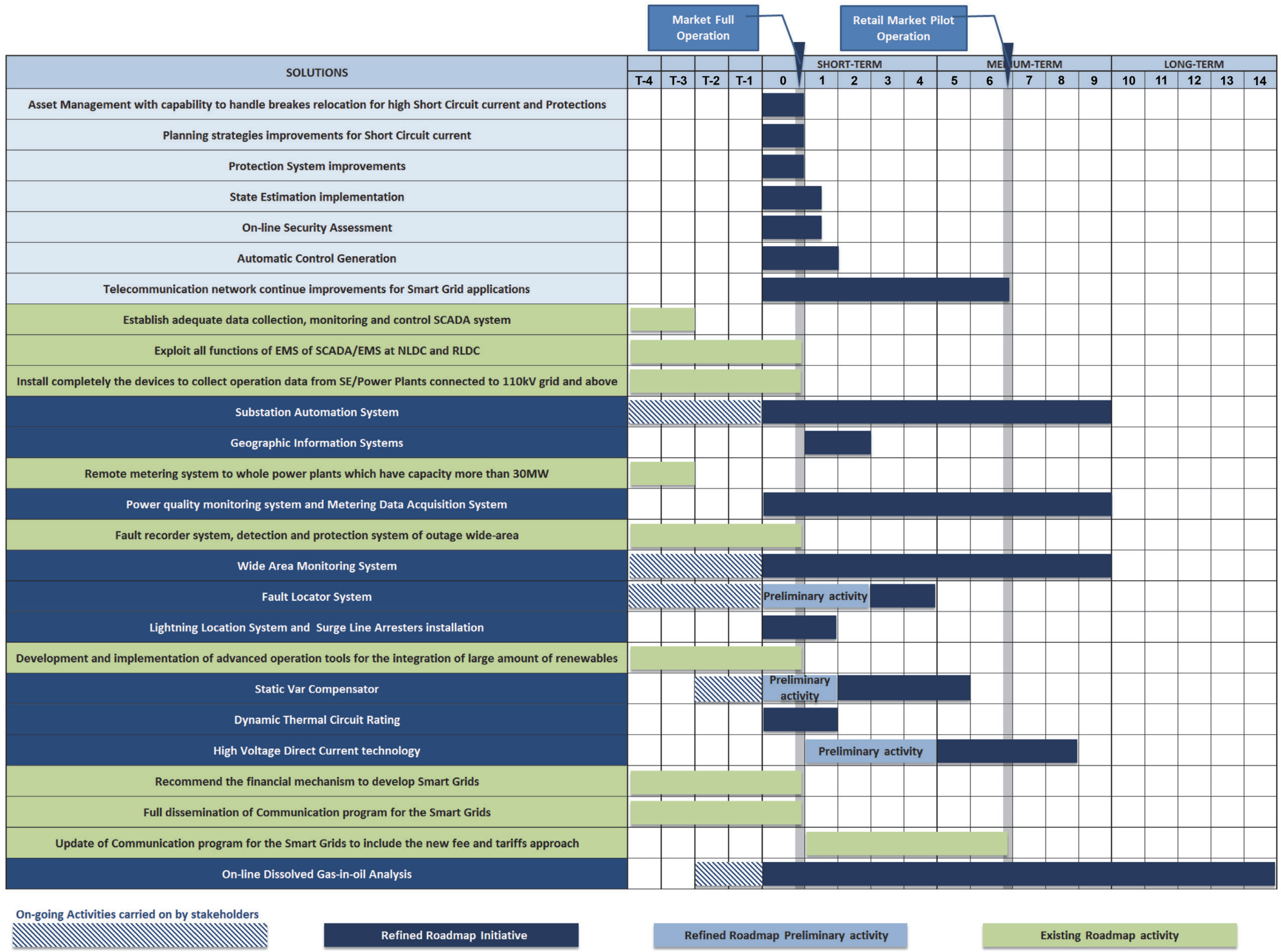
In addition a regulatory analysis and a market analysis were conducted with the aim of understanding the possible impact upon re-positioning the Smart Grid initiatives. The market roadmap and the milestones established in Decision No. 63/2013/QDTTg, dated 8 November 2013 provided a complete overview of the initiatives and the market development in Vietnam. This suggests that these roadmaps (market and Refined Smart Grid) are consistent at a high level and confirmed the most recent positioning of the Smart Grid initiatives in the timeline.

Figure 104 below shows a complete roadmap and its relationship to the market with milestones for those Smart Grid initiatives approved by Decision No. 1670QĐ-TTg (shown in green). The figure shows the refined Roadmap and the recommended "pillars" (in light blue).

In order to achieve effective Performance Monitoring of the Smart Grid Program and the impact of the Smart Grid initiatives on the power system, three different types of Key Performance Indicators (KPIs) at three different levels (shown in Figure 3) were identified in order to measure and monitor the Refined Roadmap.

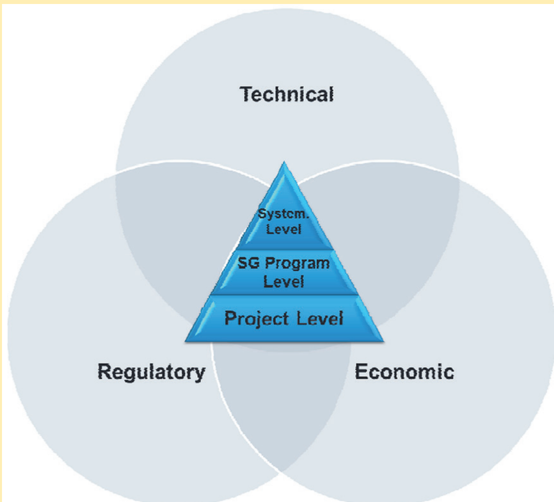
The KPIs are based on the current regulatory approach for transmission activity in Vietnam and the price control mechanism detailed in Circular No. 14/2010 /TT-BCT from 15th of May 2010. In line with the current regulation, the

FIGURE 104: COMPLETE TIME POSITIONING OF SMART GRID INITIATIVES CONSIDERING THE APPROVED ROADMAP FOR SMART GRIDS AND THE MARKET



Source: Authors

FIGURE 105: SMART GRID ROADMAP ASPECTS



Source: Authors

KPIs will set a target to be achieved and there will be penalties if the final target set by the regulator (based on the recommended values for the KPIs) is not achieved.

The KPIs address three different areas as follows:

a. **Technical**: The performance indicators for the evaluation of a successful technical implementation of each Smart Grid initiative;

b. **Economic**: The benefit/cost ratio values calculated in the Cost-Benefit Analysis; and

c. **Regulatory**: These indicators measure the effect on the projected benefits of delays or modifications in the installation steps of each Smart Grid initiative.

The KPIs monitor progress within the three aspects at three different levels. The base level or Project level is comprised of mostly technical and economic indicators. The mid-level, or Smart Grid program level focuses on the implementation progress of the program as a whole while the top level or system level measures the impact of the Smart Grid implementation on the Vietnamese power system[1].

The KPIs also pinpoint the enabling role of the Regulatory Authority which is tasked with achieving general policy targets, i.e. sustainability, reliable transmission network, and security of supply. Table 75 presents the impact of each KPI on the major objectives for the Vietnamese power system.

TABLE 75: MAP OF KPIS WITH MAJOR OBJECTIVES

		Major Objectives		
Smart Grid Initiative	KPI describing the expected improvement	Enhanced Reliability of transmission network	Security of Supply	Sustainability
Fault Locator System	Reduction of time to attend fault site by maintenance crew and elapsed time to repair	X	X	X
Wide Area Monitoring System	Voltage collapse prevention		X	
	Out-of-steps prevention		X	
Substation Automation System	Energy Not Served (ENS) reduction per year for each substation equipped with SAS	X	X	X
Lightning Location System	Percentage reduction of transient faults affecting the lines	X	X	
Metering Data Acquisition System	Mean square error between the value acquired by the meters and the value calculated by the settlement for the same meters			X
Static Var Compensator	95% variation interval of voltage level of network "pilot nodes"	X	X	X
	Voltage collapse prevention	X	X	X
Geographic Information Systems	Reduction of management costs			X
Power quality monitoring system	Percentage reduction of voltage dips			X
High Voltage Direct Current technology	The reduction of power losses			X
	High power factor		X	
On-line Dissolved Gas-in-oil Analysis	Fault number reduction	X	X	
Dynamic Thermal Circuit Rating	"Ampacity" increase	X	X	X

Source: Authors

The values of the proposed technical and economic KPIs are shown in Table 76.

The proposed regulatory KPIs aim to monitor and control the pace of evolution and implementation of each initiative within the overall Smart Grid Program. These are generic for the initiatives and measure the percentage of implementation according to the agreed target.

This document also performs a review and analysis of the Legal and Regulatory framework, highlighting the changes that have occurred over the last ten years in Vietnam's electricity market. The purpose of this analysis was to determine the policies currently in place that impact the Smart Grid initiative.

The following policies were analyzed:

a. System Security policy;

b. Renewables and their policies and incentives;

c. International Interconnection policy;

d. Quality of Service regulatory policy (indicators, incentives, penalties);

e. Smart Grid Policy; and

f. General policy for investment incentive in transmission and recovery mechanism.

The main recommendations are summarized below:

a. The system security policy is an implicit part of the Grid Code and needs to be complemented with the on-line security assessment criteria in order to avoid repeating past errors.

b. The Grid Code should also establish under the same policy, the tools that the System Operator must have in order to evaluate the security and perform on-line monitoring and on-line control of the voltage/dynamic stability of the Vietnamese Power System.

TABLE 76: TECHNICAL KPIS PROPOSED FOR EACH SMART GRID INITIATIVE

Smart Grid Initiative	Performance indicator	Technical KPI Satisfactory threshold	Economic KPI
Fault Locator System	Reduction of time to attend fault site by maintenance crew and elapsed time to repair	25%	B/C ratio: 1.17
Wide Area Monitoring System	Voltage collapse prevention Out-of-steps prevention	15%-35% 15%-35%	B/C ratio: 17.82
Substation Automation System	Energy Not Served (ENS) reduction per year for each substation equipped with SAS	100MWh	B/C ratio: 2.13
Lightning Location System	Percentage reduction of transient faults affecting the lines	20%-30%	B/C ratio: 6.89
Metering Data Acquisition System	Mean square error between the value acquired by the meters and the value calculated by the settlement for the same meters	0.4%-0.8%	B/C ratio: 39.26
Static Var Compensator	95% variation interval of voltage level of network "pilot nodes" Voltage collapse prevention	+/-5% of the rated voltage 15%-35%	B/C ratio: 1.21
Geographic Information Systems	Reduction of management costs	10%-15%	B/C ratio: 3.61
Power quality monitoring system	Percentage reduction of voltage dips	20%	B/C ratio: 39.26
High Voltage Direct Current technology	Power factor	0.7	B/C ratio: 1.56
On-line Dissolved Gas-in-oil Analysis	Fault number reduction	80%	B/C ratio: 1.13
Dynamic Thermal Circuit Rating	"Ampacity" increase	5%-25%	B/C ratio: 35.11

Source: Authors

c. The renewables policy is generally focused on wind and biomass sources. But, the criteria, methodologies and incentives established are focused on the planning procedures rather than on fostering and assessing renewable energy developments. It is recommended that the renewables policy complement the developed Smart Grid roadmap in order to take advantage of those applications that ease the integration of renewable sources in to the transmission network.

d. The international interconnection policy needs a greater degree of clarity. This may have some significance for the development and deployment of some of the Smart Grid initiatives, e.g., HVDC interconnection, more stringent requirements for online monitoring and security assessment to ensure frequency/voltage problems do not cascade from one system to another, etc. A policy that addresses these points may enable the inclusion of technologies like HVDC and to increment the use of SVC for maintaining the stability of the systems and links.

e. The Electricity Law does not define penalties or incentives for failing or exceeding the quality of service requirements. The revision of the Grid Code is also silent on the issue of penalties for failing to meet minimum standards in the quality of service. The lack of penalties weakens the introduction of Smart Grid technologies, which are being pushed by the industrial user community who have a poor perception of the quality of service of electricity supplies.

f. It is recommended that the Smart Grid policy complement Decision No.: 1670QĐ-TTg of November 2012 with both KPIs and penalties, in order to measure and track the performance of Smart Grid initiatives. As mentioned before, the final values of KPIs and penalties should be defined by ERAV based on the proposed values in this report mindful of the overall regulatory framework.

g. Finally, Circular No. 14/2010 / TT-BCT from 15th of May 2010 describes a detailed mechanism for the recovery of investments in the transmission system. The Circular clearly establishes that each year, based on the principle of ensuring full cost recovery and retaining permitted profits the operator is required to run the transmission grid according to the quality regulations and to meet key financial targets for the investment and development of the transmission grid. At present no improvements are recommended for the present mechanism.

In conclusion some recommendations for the implementation of the Smart Grid are presented. These emphasize the roles played by the different participants involved (ERAV, NPT, and NLDC). The following matrix presents the activities to be performed until the completion of the program. The responsibility assignment matrix known as the RACI matrix describes the participation by various roles in completing tasks or deliverables for the implementation of the Smart Grid program.

The main activities in order to implement the refined roadmap are those described in the Table 77.

TABLE 77: RACI MATRIX FOR THE ROLES AND RESPONSIBILITIES OF THE REFINED ROADMAP

Activity	NPT	NLDC	ERAV	IE
Internally approve the Refined Roadmap	R	R		
Present the Final Report to other institutions	R	I	I	I
Define the priorities for Implementation in the short-term	R	R	A	
Request approval of the Refined Roadmap to regulator	R	R	A	
Approve the Refined Roadmap and the Smart Grid initiatives in the short, medium and long term	C	C	R	I
Based on the recommended KPIs, define the final targets for the KPI for the implementation	C	C	R	
Include the approved investments in the Master Plan	CA	CI	I	R
Follow up the approved Smart Grid investments through the KPIs	CI	CI	R	

Source: Authors

R = Responsible; A= Accountable; C=Consulted; I= Informed.

Complementing the implementation activities of the Refined Roadmap, those agencies responsible for performing detailed studies and implementation of each Smart Grid initiative are also presented in Table 78.

A proposed Amendment to the current Smart Grid Decision was documented in the Annex "Proposed Amendment to Decision No.: 1670QĐ-TTg."

A Decision for the approval of the KPIs to control and monitor the Smart Grid initiatives is also required. it is recommended that the approval of the KPIs is performed separately from the Decision of the Refined Roadmap in order to have enough flexibility to allow ERAV to change these values (if required), without having to issue a new Decision for the Roadmap because a change of the KPI limits.

TABLE 78: RESPONSIBLE FOR DETAILED STUDIES AND IMPLEMENTATION OF THE SMART GRID INITIATIVES

Smart Grid Initiative	Responsible for Detailed Study	Responsible for Implementation
Power quality monitoring and Metering Data Acquisition Systems	NLDC	NPT
Dynamic Thermal Circuit Rating	NPT	NPT
Wide Area Monitoring System	NLDC	NPT
Lightning Location System	NPT	NPT
Geographic Information Systems	NPT	NPT
Substation Automation System	NPT	NPT
High Voltage Direct Current technology	NPT	NPT
Static Var Compensator	NLDC	NPT
Fault Locator System	NPT	NPT
On-line Dissolved Gas-in-oil Analysis	NPT	NPT

Source: Authors

C. Introduction

C.1 General Overview

This document presents the Regulatory Performance Monitoring of the Smart Grid Program and a strategy for its implementation.

The Project started by designing the strategy and gathering information in order to refine the Roadmap of the Smart Grid program for Vietnam. The execution of the project followed the sequence presented in Figure 106, which started by identifying the possible Smart Grid Applications and Smart Grid Equipment that may help to resolve the identified problems.

The methodology for developing a Smart Grid roadmap initially defined a number of essential concepts (e.g. state estimation, security assessment, remote control and regulation, asset monitoring and management) as the necessary "pillars" that are vital for the creation of a smart network.

The Task-1 report defined a common shared vision of components and equipment for the development of the Smart Grid in Vietnam starting with the current operating model and the predicted status of the electricity sector.

The Smart Grid initiatives were tailored to fit the specific needs of Vietnam, taking account of not only the best international practices and experiences, but also the current Vietnamese operational problems and the status of their Smart Grids projects.

This technical analysis identified the Smart Grid initiatives that are viable in Vietnam. Following a technology-focused investigation these Smart Grid solutions were prioritized[2].

The Cost-Benefit analysis aimed at identifying the costs and benefits of each proposed Smart Grid initiative and evaluating their economic parameters in order to understand the real added value of each initiative[3].

The Cost-Benefit Analysis (CBA) followed the key steps of the "Guidelines for conducting a cost-benefit analysis of Smart Grid projects" recommended by the Joint Research Centre Institute for Energy and Transport (JRC).

Finally, the aim of this document is to present the final phase of the Roadmap for a Smart Grid in the light of the Technical and Economic analyses, the performance monitoring of the Smart Grid Program and the revision of the legal and regulatory framework.

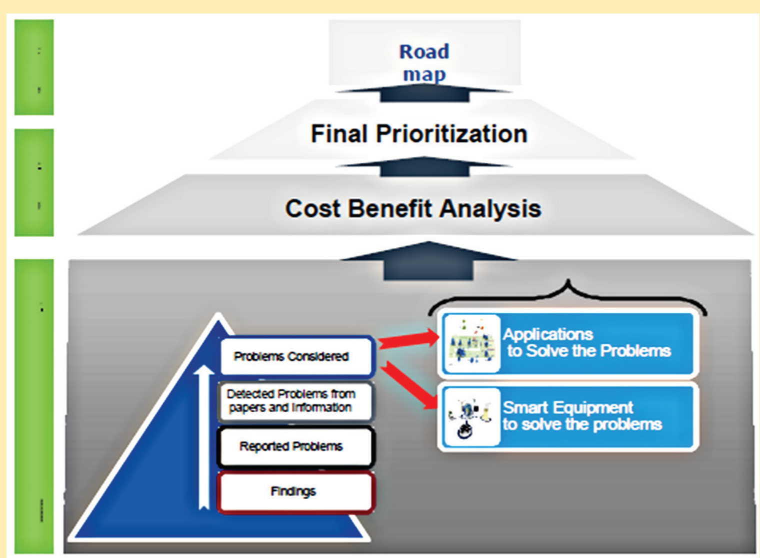
The recommendations for implementation are also presented in this document.

C.2 Document Structure

This report is structured as follows:

a. The first part is composed of chapter 'C' and presents the final refined roadmap that takes account of both the technical and economic prioritization based on the cost-benefit analysis. The initiatives have been positioned on a timeline and propose the best starting point for the solutions as well as suggested elapsed times for their development.

FIGURE 106: GENERAL OVERVIEW OF THE PROJECT



Source: Authors

b. The second part is composed of chapter 'D" and addresses the performance monitoring of the Smart Grid Program and presents the key performance indicators in order to monitor and control the implementation of the program.

c. The third part is composed of chapter 'E', which performs a review of the regulatory framework and points out possible improvements in order to expedite the approval and implementation of the Refined Smart Grid roadmap.

Finally, a summary of the key points and the recommended regulatory improvements is presented.

A dedicated Annex reports on the "Proposed Amendment to Decision No.: 1670QĐ-TTg".

D. Definition of the Refined Smart Grid Roadmap

D.1 Summary of Key Points

This chapter presents the final prioritization of all the Smart Grid initiatives relevant to the Vietnam power sector, positions them on a timeline and proposes the best starting point for the solutions as well as suggesting elapsed times for their development.

The prioritization presented below is a refinement of the Vietnamese Smart Grid roadmap and defines a phased implementation plan. This analysis has taken account of each Smart Grid initiative, namely:

a. Task 1 report: The technical reasons described in the technical analysis report; and
b. Task 2 report: The economic results of the Cost-Benefit Analysis and the risk assessment.

As in the technical analysis report three different time horizons were defined for the development of the initiatives:

a. Short term (within next 5 years);
b. Medium term (within next 10 years); and
c. Long term (within next 15 years).

In the light of a prioritization based on their cost benefit ratio, the following initiatives should start in the short term:

a. Dynamic Thermal Circuit Rating;
b. Power Quality Monitoring System and Metering Data Acquisition System;
c. Wide Area Monitoring System;
d. Lightning Location System;
e. Geographic Information Systems;
f. Substation Automation System;
g. Static Var Compensator;
h. Fault Locator System; and
i. On-line-Dissolved Gas-in-oil Analysis.

The following is achievable in the medium-term:

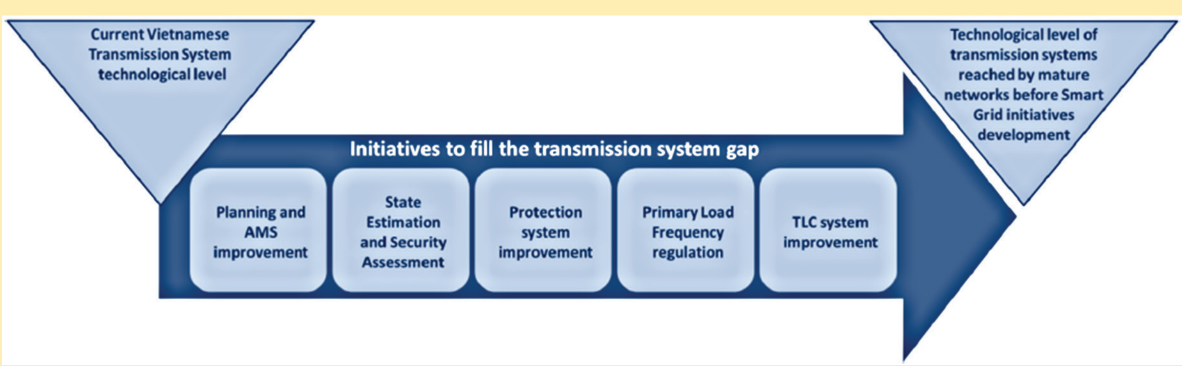
a. High Voltage Direct Current technology.

For the long-term no new initiatives have been planned, but the completion of ones already undertaken in short/medium-term is expected.

D.2 Time positioning of transmission system enhancement interventions

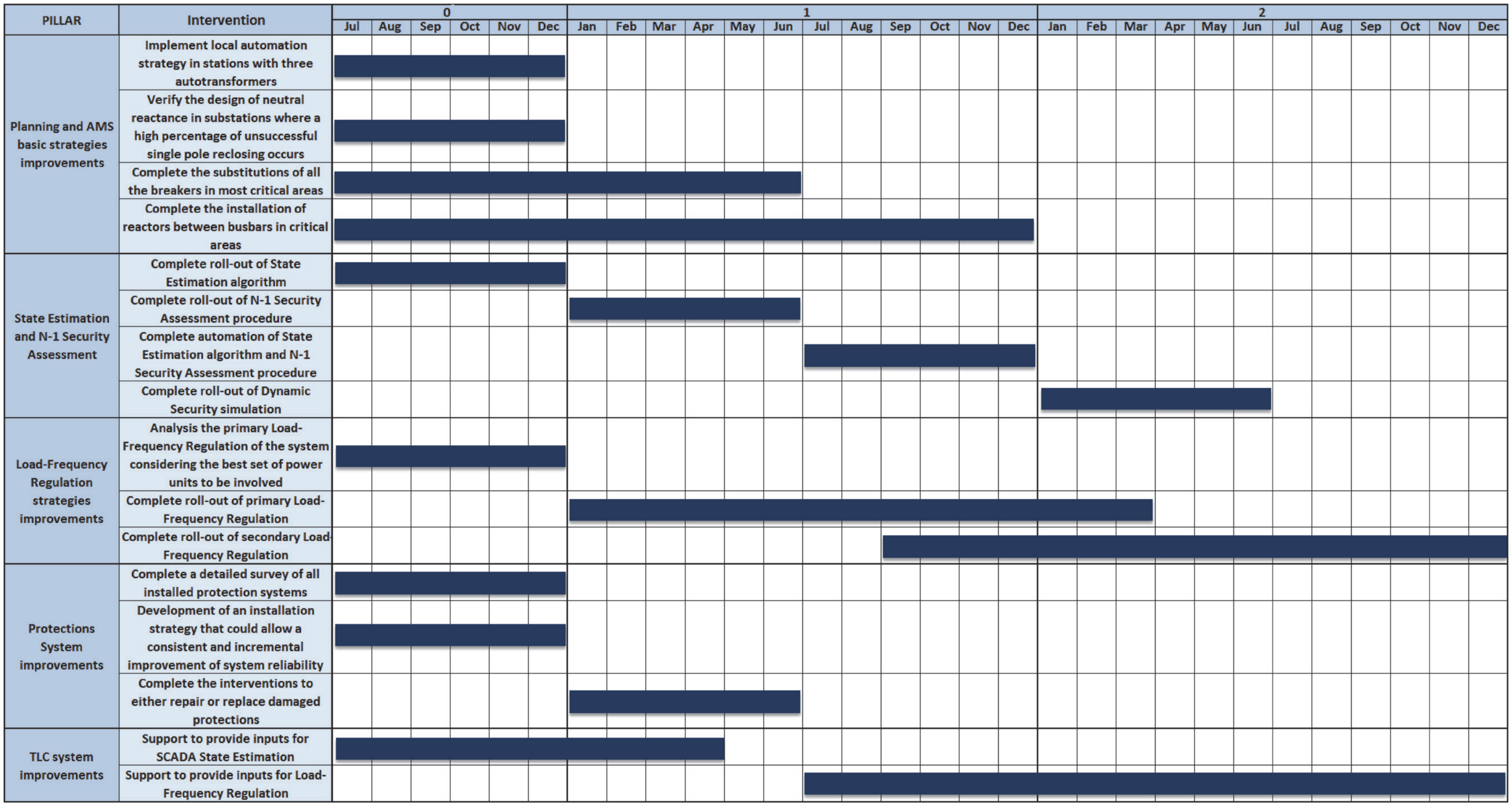
As stated in the Task-1 Report, pillars were introduced because the majority of the Smart Grid initiatives require parallel developments of multiple systems to support and/or integrate with new technologies. A case in point

FIGURE 107: TECHNOLOGICAL GAP THAT VIETNAMESE TRANSMISSION SYSTEM HAS TO FILL



Source: Authors

FIGURE 108: TRANSMISSION SYSTEM ENHANCEMENT INTERVENTIONS TIME POSITIONING



Source: Authors

is the Telecommunication (TLC) system, which is pivotal to the full development of SAS or WAMS.

To reach an adequate technological level in the Vietnamese transmission system for enabling the development of the Smart Grid a "**transmission system enhancement**" was deemed to be necessary. The gap analysis, performed in the Task-1 Report identified the following basic building blocks (or "**pillars**") as being fundamental to the success of the initiatives:

a. Planning and AMS basic strategies improvements;

b. State Estimation and N-1 Security Assessment;

c. Load-Frequency Regulation strategies improvements;

d. Protections System improvements; and

e. General TLC system improvements.

The details and the concepts shown in Figure 107 were detailed in the Task-1 Report along with a brief timeline for the implementation of the basic interventions thus completing the necessary "**transmission system enhancement**" prior to the full deployment of the Smart Grid technologies.

Figure 108 shows the various interventions required to establish the "**pillars**" depicted on a realistic timeline.

This timeline positioning is based on the information collected during the discovery process in Vietnam. These interventions do not require any prerequisite activity and can start immediately. The time durations shown for the implementation process of the different interventions is a conservative estimate based on similar activities performed in other countries (e.g. Italy). It is possible that the actual elapsed times will be less because some parallel initiatives have already been planned or are currently in progress.

D.3 Smart Grid initiatives time positioning

The following provides a brief overview of the technical and economic prioritization of some key projects:

a. The Geographic Information Systems is positioned in the short term;

b. The Dynamic Thermal Circuit Rating is positioned in the short term;

c. The Lightning Location System is positioned in the short term;

d. The Fault Locator System with recommended preliminary activities are positioned in the short term as is their finalization;

e. The Static Var Compensator with some preliminary activities are positioned in the short term whilst finalizing the expected installed capacity will impinge on the medium term;

f. Whilst the Wide Area Monitoring System starts in the short term, its complete rollout will be concluded in the medium term. The prioritization of the main data communication lines and area links are in the short term;

g. The Substation Automation System, including building/upgrading remote control centers, has already commenced and is positioned in the short term but will not be concluded until the medium term;

h. The Power Quality Monitoring system and Metering Data Acquisition System start in the short term but will not be concluded until the medium term;

i. The High Voltage Direct Current technology with the required preliminary studies and activities in the short term but will not be concluded until the medium term; and

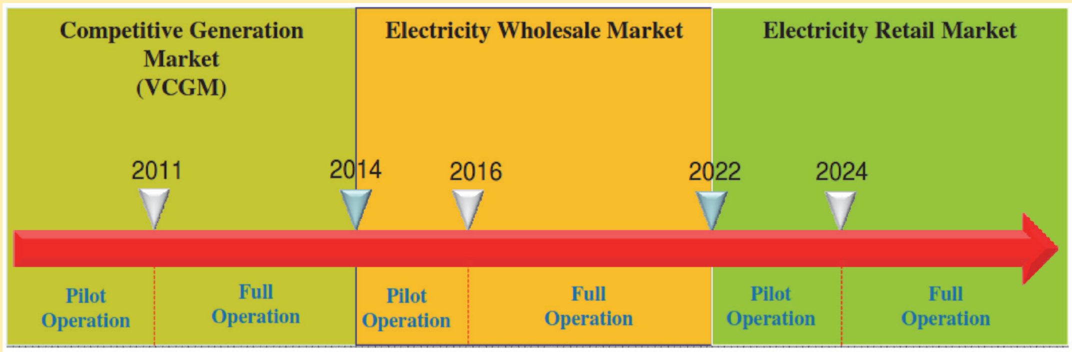
j. The On-line-Dissolved Gas-in-oil Analysis has already started and is positioned in the short term but it will last for the whole considered time horizon.

The roadmap for the development of the Smart Grid initiative in the context of the emerging Vietnamese electricity market is presented below in Figure 109. The overall aim is to consolidate and strengthen the operation of the wholesale market before introducing a retail market.

The operation of the wholesale electricity market that is planned to commence in 2016 requires that those technologies and initiatives that will most enable the implementation of the Smart Grid are initiated and in place before the year 2022. The Smart Grid technologies will help to stabilize the power supply and enhance the reliability of the transmission network. These technologies will help to increase power transfer bandwidth between north and south, which will establish a secure and reliable power supply. A stable power supply also means stable prices and provides opportunities that will attract investments and increase competition in the marketplace.

In general, the benefits for the market can be summarized as follows:

FIGURE 109: POWER MARKET DEVELOPMENT ROADMAP, PERFORMED AND PRESENTED BY ERAV



Source: ERAV, 2010, (1)

a. The ability to connect and operate of generators of all sizes and technologies;

b. Allow consumers and investors to play a part in optimizing the operation of the system;

c. Enable the integration of renewable sources help reduce the carbon footprint of the whole electricity supply system,

d. Sustain and even improve the existing levels of system reliability, quality and security of supply;

e. Sustain and improve the existing services efficiently; and

f. Foster market integration with neighboring countries to facilitate the creation of a regional integrated market.

The positioning of all the Smart Grid initiatives has been confirmed based on the technical and economic analyses as well as the current status of the Vietnamese market. These initiatives need to be in place to ensure the power market is based on a strong, reliable and self-healing transmission network. Note that the transmission system is the physical nexus where production and demand meet and it is imperative that it is consistently reliable in order to facilitate its development.

Thus, based on the technical, cost-benefit analysis as well as the power market roadmap the final positioning of the Smart Grid applications that have been positioned over the short-medium and long term are as follows:

a. **Geographic Information Systems**. It is positioned in the short term. As stated in the technical analysis, the prior development of other systems like SAS or WAMS will be important to enable the implementation of this solution which is likely to offer the largest possible number of applications that would benefit the enterprise. Given that the total cost (CAPEX: $175,000 and OPEX: $262,500) is much lower than for most of the other systems and the economic indicators are positive (EIRR: 48% and B/C ratio: 3.61) it makes sound economic and technical sense to implement this system in the short term. Further, no particular risks have been highlighted. The implementation activity basically comprises:

   i. Careful selection of all the applications that would benefit from this initiative;

   ii. Development of procedures and strategies to store and share GIS data; and

   iii. Implementation of software tools for processing and displaying data.

b. **Dynamic Thermal Circuit Rating**. This initiative has been positioned in the short term. The technical analysis had originally positioned this initiative in the long term on the basis that it would be better to wait for the current rapid growth rate of the transmission network to slow down in order to leverage this application on a large scale. However, since the CBA has revealed that its economic indicators are extremely positive (EIRR: "All positive cash flows" and the B/C ratio: 35.11), it makes both technical and financial sense to implement this technology in the short term. Developing a rigorous system operation strategy that fully exploits the dynamic rating application will easily mitigate the related risks. The implementation activity basically comprises:

   i. Careful selection of the lines to be monitored;

   ii. Choice of the monitoring devices;

iii. Development of algorithms and procedures for real-time temperature estimation; and

iv. Integration of the information and results obtained from Dynamic Thermal Circuit Rating and daily system operations.

c. **Lightning Location System**. This initiative has been positioned in the short term. The technical analysis had considered this as a short-term solution due to the criticality of the lightning problem in Vietnam. The intelligence of the system is supplied by the location system and not the arresters (which are dumb devices). The economic indicators (EIRR: 164% and B/C ratio: 6.89) strongly recommend investment in this solution. All the risks associated with this initiative can be mitigated by focusing the investments on developing applications fed by LLS data and carrying out commensurate training for the control room operators to exploit LLS information. As stated in the technical analysis report, the basic implementation phases are:

i. The evaluation of all the available technologies with respect to the specific needs of all the transmission utility functions that could benefit from such a system;

ii. The evaluation of the number of sensors needed to cover the country with the capability for homogeneous and high detection performance, event discrimination, location accuracy and 24/7 availability;

iii. The evaluation of the orography and consequently the identification of the possible ideal locations for the sensors (electromagnetic noise, structural shields, physical security, terrain, telecommunication links, etc.);

iv. Appropriate contractual agreements with local site owners wherever necessary;

v. The execution of all civil and electrical works at the identified sites, including power and telecommunication cabling if needed;

vi. The implementation of an Operational Centre provided with specific power and telecommunication schematics as well as the main server for data analysis where all sensor data will be received, processed and stored;

vii. The fine tuning of LLS (using the most immediately available data), implementing site corrections of detection parameters and thresholds where needed; and

viii. The assignment of dedicated and properly trained staff.

d. **Fault Locator System**. This initiative is positioned in the short-term. The economic indicators are lower than for other applications (EIRR: 13% and B/C ratio: 1.17) and the investment is quite high (CAPEX: $8,400,000). Also the risk assessment has highlighted that the "Investment uncertainty" is most critical for this initiative. On the other hand, the NPT FLS project is already underway and is quite independent of all the other initiatives. Therefore, the recommendation is to evaluate the real benefits of this technology on a small number of lines and then decide if it is worth deploying across the estate. For this reason only a pilot program for FLS benefits evaluation has been positioned in the short term. If in the next few years the cost of this technology decreases its current positioning can be reconsidered and, if required, brought forward. Finally, the implementation activity basically comprises:

i. Careful selection of the lines to be monitored;

ii. Installation and wiring of the devices; and

iii. Development of algorithms and procedures for FLS data exploitation.

e. **Static Var Compensator**. Some preliminary activities are required to be performed in the short term while the complete roll-out of estate-wide capability has been positioned in the beginning of the medium term. Such preliminary activity is highlighted in the final time positioning of Smart Grid initiatives. Further, the risk analysis has revealed that Vietnam's rapidly growing power network would significantly complicate the choice of the locations of SVC devices. To mitigate such risks relocatable SVCs have been suggested, which will allow the flexibility of temporary installations while retaining the investment despite unpredictable topology changes due to future growth. Even though the total cost is quite high (CAPEX: $31,500,000 and OPEX: $1,255,500) the economic indicators are good (EIRR: 14% and B/C ratio: 1.21), which make this investment a sound economic choice. Furthermore, the SVC initiative achieves significant benefits both in terms of integration of renewable energy generation and in terms of blackout prevention. Moreover, the criticality of the voltage stability issue in the Vietnamese [1] transmission network argues against delaying this measure for too long because it may jeopardize system security and availability. The plan to start its full implementation in the latter part of the short-term is very likely the right choice, as it will allow a suitable time for the detailed feasibility study phase. Therefore, the already planned devices can be installed but the full deployment of the application has to be positioned in the mid-term.

f. **Wide Area Monitoring System**. It is recommended that this application begin in the short term with the complete rollout being concluded in the medium term. The prioritization of the main data communication lines and area links are positioned in the short term. As stated in the technical analysis report WAMS is a solution that "enables" some of the others (e.g. Dynamic Thermal Circuit Rating) and aims to solve a large number of issues (e.g. voltage and transient stability, defense plan deficiencies, etc.). The sooner this initiative commences the better. Furthermore, WAMS's economic indicators are strongly positive (EIRR: 204% and B/C ratio: 17.82) and there are no unconquerable risks as long as the WAMS based applications are properly developed. The implementation activity is comprised of:

   i. Development of a remote control center;
   ii. Development of a strategy for the location of PMUs;
   iii. Installation and cabling of PMUs;
   iv. Implementation of WAMS based applications; and
   v. Integration of information and results obtained from WAMS based applications and daily systems operation.

g. **Substation Automation System**. This is a NPT project that has already reached a significant level of development. The initiative, which includes building/upgrading remote control centers, has already started and is positioned, by default, in the short term but its complete rollout will not conclude until the medium term. The economic indicators are positive and the assessed risks can be successfully mitigated with an efficient substation commissioning policy and adequate control of the gap between the roadmap and real installation pace. The implementation activity includes the installation and the commissioning of new substations equipped with SAS.

h. **Power quality monitoring system and Metering Data Acquisition System**. These initiatives are recommended for commencement in the short term but its complete rollout will not conclude until the medium term. Both these initiatives have been have been positioned in the short-term because their total cost (CAPEX: $301,500 and OPEX: $97,200) is amongst the lowest of all the initiatives while the economic indicators are compelling (EIRR: 797% and B/C ratio: 39.26). In order to mitigate the assessed risks before beginning the deployment of these initiatives it is important to carefully consider all the regulatory aspects. The implementation activity is basically comprised of:

   i. Careful analysis of all the regulatory aspects;
   ii. Development of a remote control center;
   iii. Development of a strategy for the location of devices;
   iv. Installation and cabling of devices; and
   v. Implementation of software tools for processing data.

i. **On-line Dissolved Gas-in-oil Analysis**. CBA results show that the investment is less attractive in economic terms than other initiative (EIRR: 12% and B/C ratio: 1.13) and the total cost is quite high (CAPEX: $77,592,000 and OPEX: $3,343,245). But even if the high cost of monitoring devices would make this solution a high-risk economic strategy, it is worth to consider the average lifetime of this type of transformers (about 25 years) and to start investing in this technology in the short term. The transformers' fault risk in fact is not positioned in the near future but it is widespread in all their lifetime, which is longer that the time horizon considered for the investment. As described in the technical analysis (see Report 1, paragraph 'F.11'), it is fundamental to start monitoring transformers as soon as possible in order to effectively use the stored data for an accurate diagnostic in the future (15-20 years) on aged transformers, and so fully exploit DGA technology. Therefore the benefits of this initiative are achievable only if the device installation starts in the short term.

j. **High Voltage Direct Current technology**. In order to assess the economic feasibility of the HVDC technology, the incremental cost of a new 800 km DC is link compared with the cost of an AC 500 kV solution. It has been assumed that the original planning for this installation only considered the technical benefits of the AC line rather than of the line itself in relation to the wider network. This initiative requires preliminary studies and activities that should be conducted in the short term and the implementation, if considered feasible following the findings of the study, should be positioned in the medium term. However, at the outset it can be safely assumed that the economic indicators are good with regard to the technology application per se and not the line itself. Further, despite the fact that the total incremental costs are very high (CAPEX: -$16,800,000 and OPEX: $118,098,000), the EIRR has "All positive cash flows" the B/C ratio is 1.56. The economic indicators currently ignore several other strategic and technical benefits that if included would likely make a very strong case for the development of HVDC technology in Vietnam. On balance it is worth planning the development of this technology because it could prove useful for both interconnections with neighboring countries [1] and for long links (e.g. 500kV link with a length greater than 700km) connecting the Northern and Southern parts of Vietnam. Furthermore, HVDC technology is perhaps the most ideally suited Smart Grid initiative for integrating new variable renewable generation. In fact the increased transfer capacity and active power control are fundamental benefits which would enable the installation of wind or solar power plants carrying the generated energy to the load areas and balancing the natural fluctuation of renewables. The actual implementation of HVDC is reliable only in the medium term since this initiative requires quite a long preliminary activity (about 4 years), necessary for the feasibility study. Such preliminary activity is highlighted in the final timeline positioning of the Smart Grid initiatives. After this study phase the real implementation activity (comprised of the construction of the HDVC line/s) can start and may take, based on the consultant's experience, about 4 years to complete.

The creation of a timeline for the prioritization of the Smart Grid initiatives assumes a specific starting point at which the clock starts. Some of the initiatives have a development and installation cycle as long as five years prior to becoming operational and economically beneficial to the organization. The development process for SAS is already underway which is why it is has been positioned as a short term project i.e. within the next 5 years even though the installation will not actually be concluded until towards the end of the medium term. Equally the full implementation of WAMS, the Power quality monitoring system and the Metering Data Acquisition System, which are intertwined with the installations of new substations, will also be completed within the same ten-year window.

Figure 110 represents the final time positioning of Smart Grid initiatives and defines the phased implementation plan for the Refined Vietnamese roadmap.

The broad brushstrokes for the prioritization of the Smart Grid initiatives have been completed. The project map shown below depicts the approved market rollout in Vietnam and is based on the ratification provided by "Decision No. 1670QĐ-TTg" of November 2012 [2] approving the development of both the Smart Grid and the "pillars" required to enhance the transmission system.

The complete map presented below in Figure 111 shows the final timeline positioning of the Smart Grid initiatives and defines the implementation of the refined roadmap. "Decision No. 1670QĐ-TTg" solutions are shown in green, the Smart Grid initiatives in blue and the "pillars" in light blue.

"Decision No. 1670QĐ-TTg" defines three different horizons for the development of the Smart Grid:

a. Phase 1/initial phase (2012-2016);

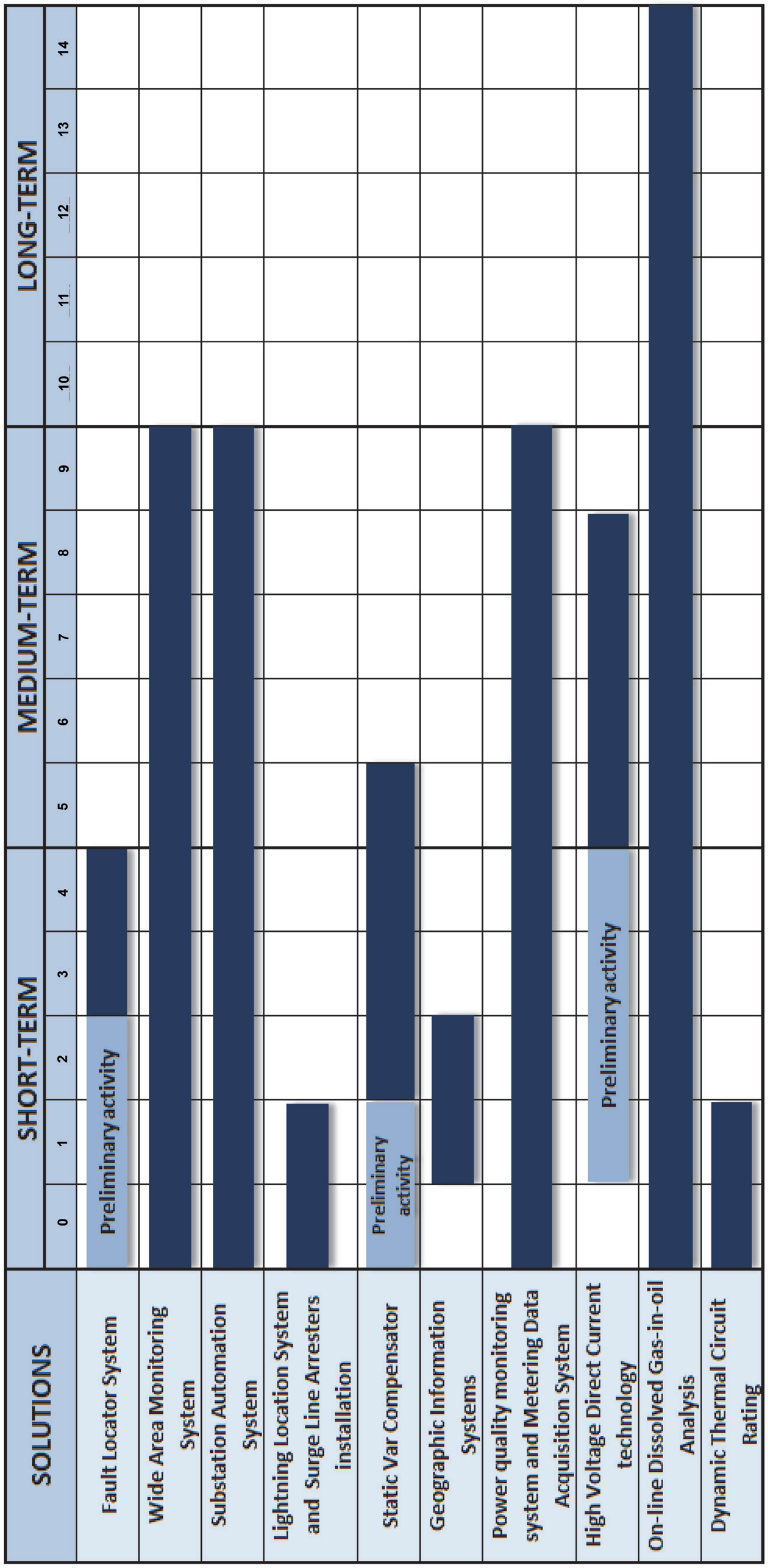
b. Phase 2 (2017-2022); and

c. Phase 3 (after 2022).

This document refers to different initiatives for the Vietnamese electrical system developments taking into account both transmission and distribution networks. The distribution networks are outside of the scope of this project and have not been shown in Figure 111. While the applications for the distribution network are well detailed, only generic interventions and improvements for the transmission network have been shown; for example, the "Development and implementation of advanced operation tools for the integration of large number of renewables", listed in "Decision No. 1670QĐ-TTg", is a clear objective but not a specific application.

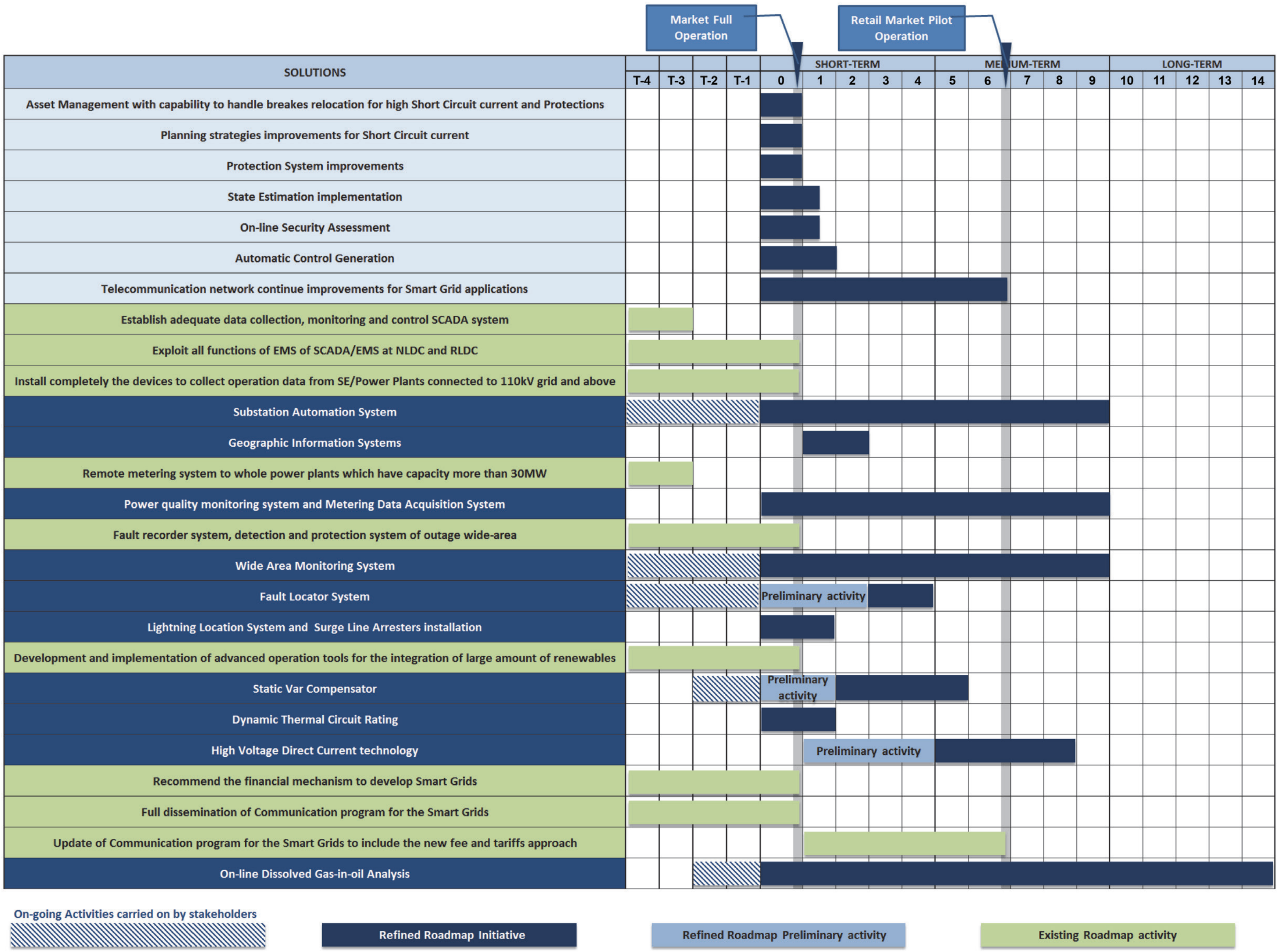
Conversely, both the "pillars and the Smart Grid initiatives, described previously in this chapter, address specific applications for the transmission system. These, therefore, are consistent with the requirements stated in "Decision No. 1670QĐ-TTg" for the transmission system. For example, some Smart Grid applications like Static Var Compensators, High Voltage Direct Current technology or Dynamic Thermal Circuit Rating can be considered amongst the best Smart Grid initiatives

FIGURE 110: FINAL TIME POSITIONING OF SMART GRID INITIATIVES



Source: Authors

FIGURE 111: COMPLETE TIME POSITIONING OF SMART GRID INITIATIVES CONSIDERING THE APPROVED ROADMAP FOR SMART GRIDS AND THE MARKET



Source: Authors

in terms of the integration with new variable renewable generation. In fact, increased transfer capacity is a fundamental benefit, which will enable the installation of wind or solar power plants carrying the generated energy to the load areas. Such an objective is entirely consistent with the target referred to by the requirement "Development and implementation of advanced operation tools for the integration of large amount of renewables". Further, initiatives like "Wide Area Monitoring System", "Fault Location System" and "Lightning Location System and Surge Line Arresters installation" are viable solutions to meet the requirements of the stated target "Fault recorder system, detection and protection system of outage wide-area".

E. Performance Monitoring of the Smart Grid Program

E.1 Key Points Summary

This chapter contains the Key Performance Indicators required to measure and monitor the Refined Roadmap. The key performance indicators will measure the progress towards a Smart Grid and assess the level of smartness.

The proposed indicators specify the enabling role of the Regulatory Authority who is tasked with achieving general policy targets, i.e. sustainability, reliable transmission network, competitiveness and security of supply. The framework introduces three types of KPIs, each with two different levels having a specific program goal, individual initiatives goal as well as a technical goal for the Refined Roadmap. The use of such KPIs will support the preparation for the deployment of the Smart Grid applications.

KPIs for the Refined Vietnamese Roadmap have three main roles:

a. They measure the efficiency of the implementation processes, which are aimed at meeting the goals of the NPT and are embedded within the Master Plan and regulatory targets;

b. They form the basis of the monitoring process of the Smart Grid implementation activities, thus showing that each application is delivering various elements of new functionality needed in the transmission network in order to meet the overarching goals of the program; and

c. They support the Smart Grid regulatory process, which links the expected impacts of each Smart Grid application to the deployment conditions.

The KPIs therefore aim to measure the contribution of the Smart Grid applications in the context of the technical, economic and regulatory aspects. The results will help ERAV and the various stakeholders to track the benefits and the expected results of the Smart Grid applications.

E.2 The Transmission Regulation in Vietnam

Electricity transmission services are characterized by a number of peculiarities that affect the manner in which they are regulated. The peculiarities include very distinct timing issues, a monopoly over supply and vertical economies with generation and load.

Transmission is a monopolistic service. The economics of transmission investment and the economies of scope and scale of service provision ensure that this will be the case for some time to come. Therefore, transmission service elements (e.g. prices) must be regulated. Regulation of the transmission provider is a substitute for competition, and therefore, its core objective is to prevent the transmission provider from charging customers a price above what would be the competitive price for access and use [3]. In general, the regulator is also seeking to effect efficient operations and investment decisions by motivating the transmission provider to manage the system so it complements generation and distribution and enables competition in wholesale electricity trade in both the short and long term.

The challenges for the regulation of transmission areas are threefold, regardless of the structure of ownership. First, transmission is subject to network externalities associated with real time operations such as loop flow, congestion and losses. This makes it difficult to assign responsibility for the marginal real-time system costs caused by transmission users. In turn, this makes defining and assigning property rights difficult, especially if use of the grid is measured inaccurately or not at all as it is today in some parts of the grid. Therefore, it makes relying on market-based investment and participant-funded transmission expansion much more challenging.

Second, investment in transmission networks exhibit significant economies of scale and scope, lumpiness and externality effects. Scale effects in transmission occur because the incremental cost of doubling the size of a new line may significantly lower the average cost per MW compared to a line only half the size. In addition, grid expansion comes in fixed sizes, which means that additions cannot be made in small increments of 1 MW to match the demand of individual customers. This means that many efficiently sized market-based transmission investment projects are too large and hence too risky for any single market participant. Furthermore, the benefits (i.e., the positive externalities) associated with an increase in the transfer capability of the grid are nearly universally enjoyed.

Third, because of the strong network externalities associated with investments that both widen and deepen the transfer capability of the system (especially the high voltage system), expansion planning and investment processes suffer from a 'free-loader' problem.

Further, considering these challenges and broader international experience in the regulation of the transmission activity, several approaches were considered and implemented in order to regulate transmission activity. The interest in incentive regulation is not due to new contributions from economic theory. Rather, the need for practical solutions has resulted in design and implementation of regulatory arrangements that are not necessarily in line with the theory [4]. The regulatory reforms have emerged as an alternative to the traditional rate-of-return (ROR) or cost-of-service (COS) regulation of utilities and regulators have adopted a variety of approaches to incentive regulation. The main approaches to Incentive Regulation can be summarized as follows [5].

Rate of Return Regulation: The ROR regulation is the traditional approach to regulation of privately owned monopolies and an alternative to public owned utilities. The method is a heavy-handed approach to regulation and it is generally identified with the regulation of investor-owned utilities. The ROR regulation allows the utility to cover its operating and capital costs and earn a return on capital.

Price Cap Regulation: The price cap approach to utility regulation is perhaps the most widely discussed and significant innovation in utility regulation and a viable alternative to ROR regulation. The method was first proposed in Littlechild in 1983 and various versions of it have since been adopted in the regulation of infrastructure and utility industries in the United Kingdom and other countries. Price cap regulation essentially decouples the profits of the regulated utility from its costs by setting a price ceiling. The method is also referred to as the 'RPI-X' model. For each rate period, normally between 3 to 5 years, the price cap for each year is set based on the Retail Price Index and an efficiency factor X. Prices remain fixed for the rate period and the utility keeps or shares the achieved cost savings.

Revenue Cap Regulation: The revenue cap method regulates the maximum allowable revenue that a utility may earn. Similar to the price cap regulation, the aim of the regulator is to provide the utility with incentive to maximize its profits by minimizing the costs and allowing the utility to keep the cost savings achieved during the regulatory lag.

Sliding Scale (ROR bandwidth): In sliding scale or ROR bandwidth regulation, the utility's allowed rate of return is benchmarked against a target or reference ROR that lies within a pre-specified dead-band. During the regulatory lag, the actual ROR can vary within the dead-band without causing rate adjustments. If the actual ROR falls outside the dead-band it can trigger profit sharing mechanisms or rate reviews.

Yardstick Regulation: In yardstick regulation the performance of a regulated utility is compared against that of a group of comparable utilities. For example, the mean of the costs of a peer group of firms can serve as performance benchmark. The method was first proposed in Shleifer 1985 and it is used to promote indirect competition between regulated utilities operating in geographically separate markets.

Partial Cost Adjustment: Another approach to incentive regulation is to link the price adjustments to changes in the utility's own costs observed in a reference year. The cost minimization incentive is provided by periodic adjustments to prices that are less than proportional to the actual changes in the costs.

Menu of Contracts: The menu of contracts method is an innovative approach to reduce the information asymmetry between the regulator and regulated firm. Under this scheme the regulator offers the utility a menu of incentive plans with a constant consumer welfare component. The utility can choose between the incentives and the flexibility in choosing among the alternatives reveals its welfare-enhancing preferences.

The various incentive regulation methods presented above are usually not observed in a pure form. Rather, practical considerations and multiplicity of the regulatory objectives often result in using a combination of different incentive regulation methods. For example, targeted incentive schemes can supplement the broad incentive regulation methods. Also, incentive regulation may be combined with various profit or loss sharing schemes. However, hybrid schemes may result in inefficient resource allocation.

Considering the Vietnamese context, the regulation of the transmission activities, i.e. the price control mechanism and methodology are established in Circular No. 14/2010 / TT-BCT from 15th of May 2010. Article 3 of this regulation establishes that:

a. The annual electricity transmission price is uniformly applied at a national level regardless of the transmission distance and place of delivery.

b. The average transmitted power is determined each year, according to the principle of ensuring **full cost recovery** and **permitted profits** to operate the transmission grid according to the quality regulations and to meet key financial targets for the investment and development of the transmission grid.

c. The average annual transmission price is determined on the basis of the total electricity transmission revenues allowed for a year for the National Power Transmission Corporation and assigned to the Unit that must pay the cost of power transmission at the point of delivery of electricity.

The total electricity transmission revenues allowed annually are referred to as the total capital cost for a year allowed for the National Power Transmission Corporation[4] plus the total cost of the operation and maintenance of transmission allowed for the year plus the adjustment of revenues of the previous year.

The transmission regulation in Vietnam is close to a Rate-of-Return regulation with a push for efficient costs to be approved by ERAV. In this schema overall cost of the transmission activity plus a return are fully recognized by regulation. So, there are no incentives except to avoid penalties for quality indicators such as the annual target for Energy Not Served in MWh as defined by ERAV from time to time[5] and a losses target[6] [6].

On the other hand, it is important to consider the current stage of the Vietnamese electricity market and the considerable gap between the SAIFI and SAIDI indicators relative to the mature power systems of developed countries as previously reported[7].

Considering the previous statements and the regulatory approach for the transmission activity in Vietnam, the KPIs to be designed should only have a penalty mechanism if they exceed the approved values by ERAV.

E.3 Design of the Key Performance Indicators for the Refined Roadmap

In order to design KPIs for the Refined Roadmap, the following characteristics should be considered:

a. Meaningful: this means that a KPI relates to the expected innovation, impact, and therefore makes sense since it is contributing to the achievement of the overarching goals.

b. Understandable: this means that the KPI definition relates clearly to the expected impacts of the Smart Grid application.

c. Quantifiable: this means that values derived from their implementation and testing are used to develop the status of their contribution to the improvement of the network.

Given the current transmission regulation in place, the KPIs proposed take account of 3 different types or aspects (shown in Figure 112) for the evaluation of the success of the Smart Grid initiatives and their inherent level of smartness:

a. **Technical**: The performance indicators to measure the success of the technical implementation of each Smart Grid initiative;

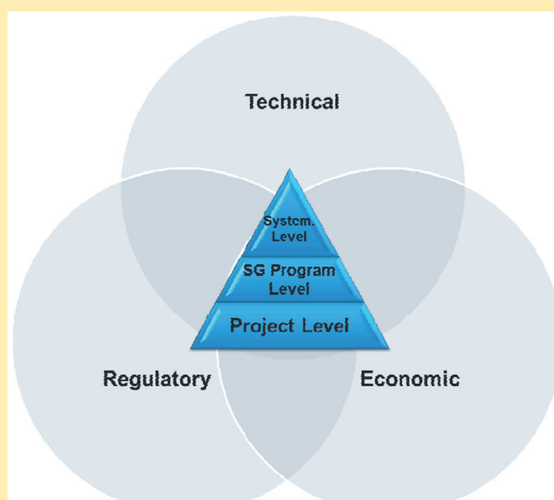
b. **Economic**: The benefit/cost ratio values calculated in the Cost-Benefit Analysis; and

c. **Regulatory**: The indicators to measure how the delay or the modifications in the installation steps of each Smart Grid initiative affect its benefits.

Each aspect also considers the project level, Smart Grid program implementation level and system level for the KPIs.

On the other hand, each KPI could be tied to major objectives for the whole system and part of a regulatory energy policy. In this case, we assume that the main major goals of the system are:

FIGURE 112: KPI BY TYPE AND LEVEL



Source: Authors

a. Enhancement of the transmission network reliability;

b. Increase the Security of supply; and

c. Sustainability of the power system.

The KPIs mapped to those major objectives are presented in Table 79.

Each proposed KPI mapped to general objectives will have a defined value in the appropriate range. The values in the range are derived from international best practices and the Consultant's experience[8]. They were part of the assumptions in the developed model for the cost benefit analysis. The details are presented in the following paragraphs.

In order to effectively track these KPIs and the pace of implementation of the Smart Grid initiatives, some statistics are required to be gathered by NPT. This proposal is presented in the next chapter.

E.4 Technical Key Performance Indicators

As stated in the technical analysis and in the previous chapter, the metrics for the technical evaluation of each Smart Grid initiative implementation are as follows:

a. **Fault Locator System**. In order to evaluate the success of the FLS initiative, it is important to measure the reduction in the time taken for the intervention of maintenance crews during an outage event. The FLS application will be considered satisfactory if after its implementation such times are reduced by at least 25%.

b. **Wide Area Monitoring System**. The evaluation of the success of WAMS initiative is a very complex area and entirely contingent upon the applications and functions developed using PMU data. For example, an evaluation of a voltage

TABLE 79: MAP OF KPIs WITH MAJOR OBJECTIVES

Smart Grid Initiative	KPI describing the expected improvement	Major Objectives: Enhanced Reliability of transmission network	Major Objectives: Security of Supply	Major Objectives: Sustainability
Fault Locator System	Reduction of time to attend fault site by maintenance crew and elapsed time to repair	X	X	X
Wide Area Monitoring System	Voltage collapse prevention		X	
	Out-of-steps prevention		X	
Substation Automation System	Energy Not Served (ENS) reduction per year for each substation equipped with SAS	X	X	X
Lightning Location System	Percentage reduction of transient faults affecting the lines	X	X	
Metering Data Acquisition System	Mean square error between the value acquired by the meters and the value calculated by the settlement for the same meters			X
Static Var Compensator	95% variation interval of voltage level of network "pilot nodes"	X	X	X
	Voltage collapse prevention	X	X	X
Geographic Information Systems	Reduction of management costs			X
Power quality monitoring system	Percentage reduction of voltage dips			X
High Voltage Direct Current technology	The reduction of power losses			X
	High power factor		X	
On-line Dissolved Gas-in-oil Analysis	Fault number reduction	X	X	
Dynamic Thermal Circuit Rating	"Ampacity" increase	X	X	X

Source: Authors

stability-monitoring feature based on WAMS may be considered successful if it is instrumental in preventing 15%-35% of voltage collapses. The actual percentage gains depend on the topology of that portion of the network involved in the voltage instability event. Equally, an evaluation of a transient stability monitoring function on WAMS might be considered successful if it helps to prevent 15%-35% of power plants falling out-of-step. As with the voltage collapse case the actual percentage gains depend on the topology of the portion of the network involved.

c. **Substation Automation System**. The key performance indicator (KPI) for the evaluation of such an initiative is the reduction of Energy Not Served (ENS). A SAS implementation will be considered successful if the reduction in the average value of Energy Not Served (ENS) per year for each substation equipped with SAS is above 100MWh.

d. **Lightning Location System**. The installation of Transmission Surge Line Arresters (guided by Lightning Location System data analysis) will be considered successful if it results in a 20%–30% reduction of transient faults.

e. **Metering Data Acquisition System**. To evaluate the success of the Metering Data Acquisition System it will be necessary to measure the mean square error between the value acquired by the meters and those used in the original baseline calculated by the settlement for the same meters. A satisfactory value will be in the range from 0.4%-0.8% interval.

f. **Static Var Compensator**. To evaluate the performance of the SVC system it would be appropriate to measure the variation of the voltage level of the most important network nodes (named "pilot nodes"). If 95% of such variations are within +/-5% of the rated voltage the result could be considered satisfactory. Furthermore, as for the WAMS evaluation, a SVC may be considered to be operating successfully if it is key to preventing 15%-35% of voltage collapse in effected parts of the network.

g. **Geographic Information Systems**. In order to evaluate the success of the GIS application it will be necessary to measure the reduction in the cost of managing the energy network. A satisfactory value for such a reduction will be in the range of 10%–15%.

h. **Power quality monitoring system**. A suitable KPI is the percentage reduction of voltage dips where a value above 20% can be considered satisfactory.

i. **High Voltage Direct Current technology**. To evaluate the success of an HVDC link installation it will be necessary to measure the power losses and the load factor on the line. In order to effectively reduce the power losses (not only in percentage terms but also in absolute terms) the line has to be fully exploited, making it carry a large amount of power (this is a key feature of HVDC technology which has the potential for enormous bandwidth). Therefore, for evaluating if the choice of a DC link instead of an AC line has been successful, the load factor represents the crucial technical KPI. A value above 0.7 can be considered satisfactory.

j. **On-line Dissolved Gas-in-oil Analysis**. The DGA installation initiative can be considered successful if the use of the monitoring systems consistently results in the prevention of transformer outages. A reduction by 80% in the number of faults could be considered a satisfactory value.

k. **Dynamic Thermal Circuit Rating**. According to international experiences, which are also borne out by the Vietnamese Smart Grid roadmap, the dynamic ratings are typically 5% to 25% higher than conventional static ratings. So, if on the lines where the DLR is applied the "ampacity" increases from between 5% to 25% the results of DLR implementation will be considered satisfactory.

The proposed KPI metrics for the technical evaluation of each implemented Smart Grid initiative are summarized Table 80.

Apart from the preceding technical metrics it is also important to have the following statistics in order to better evaluate the impact of the Smart Grid implementation and to determine some of the previous technical KPI:

a. MW of transfer capacity of HVDC link.

b. Interconnection Capacity increase (MW) between transmission system and Distribution Systems before and after the implementation of a Smart Grid application.

c. Interconnection Capacity in MW of direct current flowing between neighboring countries and the Vietnamese Interconnected system (not isolated areas).

d. The number of events that result in brownouts and blackouts. The Energy Not Served associated with every event and discriminated by type of users affected, i.e. industrial zones in particular as well as others.

TABLE 80: TECHNICAL METRICS IDENTIFIED FOR SMART GRID SOLUTIONS

Smart Grid Initiative	Performance indicator	Technical KPI Satisfactory threshold
Fault Locator System	Reduction of time to attend fault site by maintenance crew and elapsed time to repair	25%
Wide Area Monitoring System	Voltage collapse prevention	15%-35%
	Out-of-steps prevention	15%-35%
Substation Automation System	Energy Not Served (ENS) reduction per year for each substation equipped with SAS	100MWh
Lightning Location System	Percentage reduction of transient faults affecting the lines	20%-30%
Metering Data Acquisition System	Mean square error between the value acquired by the meters and the value calculated by the settlement for the same meters	0.4%-0.8%
Static Var Compensator	95% variation interval of voltage level of network "pilot nodes"	+/-5% of the rated voltage
	Voltage collapse prevention	15%-35%
Geographic Information Systems	Reduction of management costs	10%-15%
Power quality monitoring system	Percentage reduction of voltage dips	20%
High Voltage Direct Current technology	Power factor	0.7
On-line Dissolved Gas-in-oil Analysis	Fault number reduction	80%
Dynamic Thermal Circuit Rating	"Ampacity" increase	5%-25%

Source: Authors

e. A table with the details of the disconnected loads, value of the demand disconnected (MW), the duration of the disconnection should be elaborated in order to determine the Energy Not Served of each event. An analysis of the precise cause of each event of the Vietnamese power system stability (which resulted in either brown-outs or just an event without any transmission component disconnected) The classification of each Power System Stability event should follow the classification shown in Figure 113.

f. Determine if the event can be analyzed in terms of the precise cause/s using the installed WAMS.

g. For each event determine the last time that the N-1 analysis was conducted (months, days, minutes, etc.).

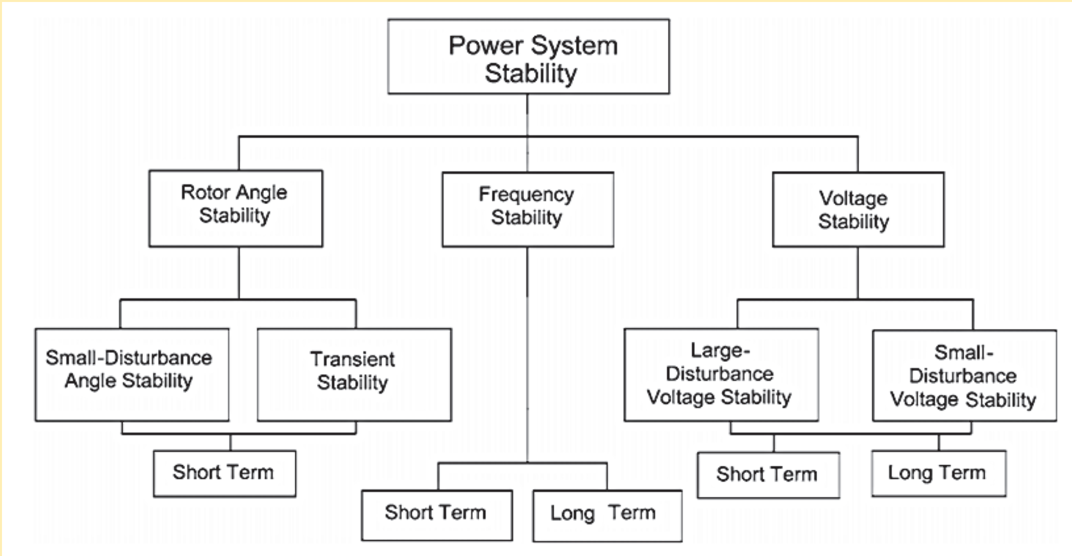
E.5 Economic Key Performance Indicators

The Cost-Benefit Analysis calculated some indicators to evaluate the economic success of the investment in the proposed Smart Grid initiatives and these can be considered as the economic targets to be achieved.

The B/C ratio values of the various Smart Grid initiatives are listed in descending order by value in Table 81.

These KPIs are for those applications that produced the best results in the economic analysis. During the implementation of the Smart Grid initiatives, the cost benefit ratio must be tracked and compared with the baseline values listed in the table above. Any reduction of the ratio will be considered indicative of the increasing costs of the initiative.

FIGURE 113: CLASSIFICATION OF POWER SYSTEM STABILITY EVENTS



Source: IEEE / CIGRE, 2003, (2)
Note: Voltage Stability is also called Voltage Collapse.

TABLE 81: SUMMARY OF THE SYNTHETIC VALUES OF THE ECONOMIC BENEFITS OF SMART GRID INITIATIVES

Smart Grid Initiative	Economic KPI
Power quality monitoring and Metering Data Acquisition Systems	B/C ratio: 39.26
Dynamic Thermal Circuit Rating	B/C ratio: 35.11
Wide Area Monitoring System	B/C ratio: 17.82
Lightning Location System	B/C ratio: 6.89
Geographic Information Systems	B/C ratio: 3.61
Substation Automation System	B/C ratio: 2.13
High Voltage Direct Current technology	B/C ratio: 1.56
Static Var Compensator	B/C ratio: 1.21
Fault Locator System	B/C ratio: 1.17
On-line Dissolved Gas-in-oil Analysis	B/C ratio: 1.13

Source: Authors

E.6 Regulatory Key Performance Indicators

From the point of view of the regulatory perspective the success of each Smart Grid initiative can be evaluated using the following indicators:

a. At an individual level, an indicator that measures the pace of implementation for the approved initiative.

b. At an individual level, an indicator that measures the gap between an acceptable cost-benefit ratio (considering the possible delays and likely new conditions), with respect to the baseline presented in the approval stage.

c. At the system or program level, an indicator that measures the number of Smart Grid initiatives launched in the short-term over the total number of planned initiatives in the short-term.

d. At the system level, an indicator that measures the results delivered by the Smart Grid initiatives in the short-term.

e. At the program level, a Smart Grid Effectiveness Index based on a weighting for each initiative launched and result obtained. The Regulatory Authority should assign the proper weighting for each initiative.

Those indicators will only apply after the approval of the proposed refined roadmap.

F. Revision of the Legal and Regulatory Framework

F.1 Key Points Summary

This chapter presents a review and analysis of the Legal and Regulatory framework, highlighting the changes that have occurred over the last ten years in Vietnam's electricity market. The purpose of this analysis was to determine the aspects and policies currently in place that impact the Smart Grid policy.

The following policies were analyzed:

a. System Security policy;

b. Renewables and their policies and incentives;

c. International Interconnection policy;

d. Quality of Service regulatory policy (indicators, incentives, penalties);

e. Smart Grid Policy; and

f. General policy for investment incentive in transmission and recovery mechanism.

Finally, recommendations for the implementation of the Refined Roadmap are performed as well as a definition of the roles and responsibilities of the stakeholders.

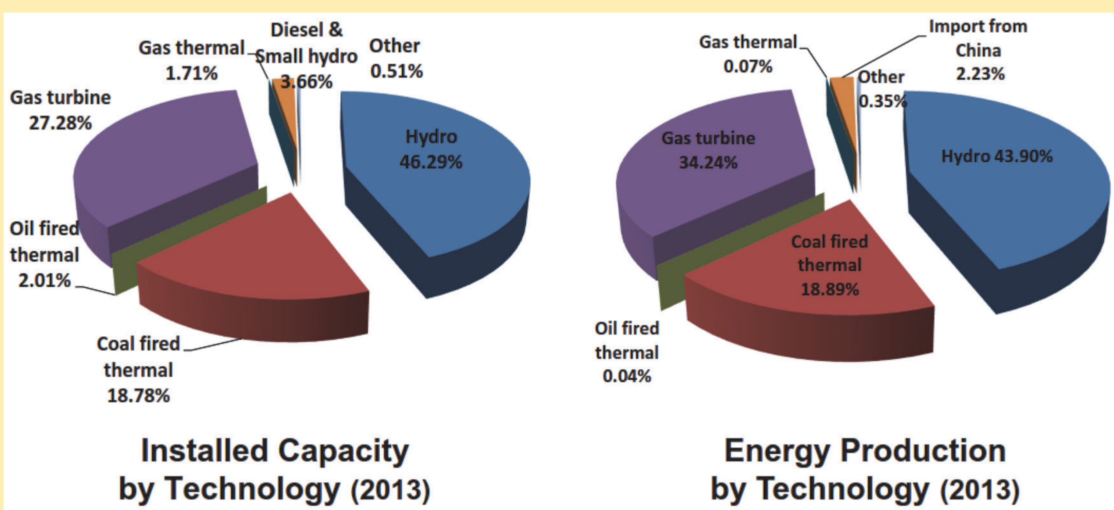
F.2 The Legal Framework

The regulatory framework in Vietnam has changed quite significantly in the last ten years as it has sought to consolidate and develop an electricity wholesale market commensurate with the fast growing demands of the country. At the time of passing the Electricity Law, Vietnam had a peak demand of 8.3 GW and an installed capacity of 10.6 GW [7]. In 2013 the peak demand reached 20 GW while the installed capacity was 30.4 GW with a further significant increase in the offing.

The introduction of the Electricity Law allowed the diversification of investments (see Figure 114), in the power sector facilitating the participation of all economic sectors. The Law also created the electricity market and stipulated the step-by-step development of competitive generation as well as wholesale and retail competitive markets.

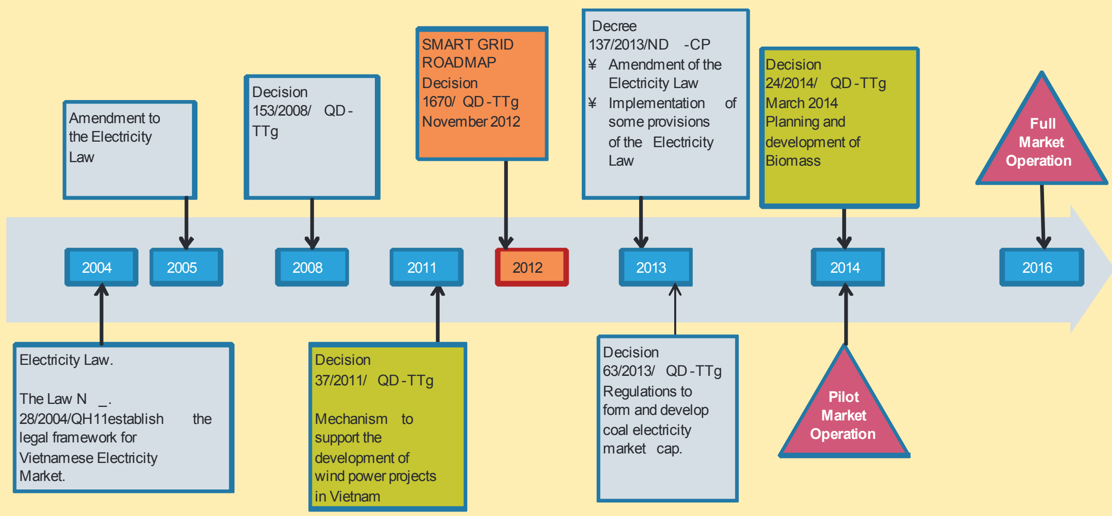
These antecedents and the development of the subsequent legal framework based on the Electricity Law of 2004, is analyzed in the light of the main Decisions passed by the Regulator and/or the Ministry.

FIGURE 114: INSTALLED CAPACITY AND ENERGY PRODUCTION IN 2013



Source: Authors

FIGURE 115: TIMELINE AND OVERVIEW OF THE LEGAL FRAMEWORK OF VIETNAM



Source: Authors

A timeline and overview of the electricity legal framework is presented in Figure 115. The green box represents the Decisions passed in Vietnam regarding renewables, while the orange box represents the Decision regarding the Smart Grid initiatives, which was passed in November 2012.

The legal framework directly or indirectly affects the development of a Smart Grid policy. The major milestones in market development, depicted above in Figure 115, are also important and they were factored into the final prioritization of the proposed Smart Grid strategy roadmap.

The next paragraphs will analyze the most significant Decision for the development of a Smart Grid policy.

F.3 The Electricity Law

The narrative presented below analyses Electricity Law No. 28/2004/QH11[9], passed in 2004, with a particular focus on Article 4, and some of the key policies that were subsequently developed.

The level of detail of the policies contained in the law is adequate following the traditional Kelsen pyramid of the juridical framework. The Electricity Law is the appropriate base to develop the next juridical level, which is comprised of the bylaws and/or Decisions in order to implement these policies for the electricity sector.

Our analysis shows that the Electricity Law has implications for developing policies on renewables, new technologies, the energy market and competition in general. Further, it establishes the transmission of energy as a monopolistic activity to be performed exclusively by the State of Vietnam.

In particular, the third paragraph of Article 4 addresses the development of a Smart Grid policy: "… apply scientific and technological advances to electricity activities and use with a view to saving, raising the efficiency of using various energy sources, protecting the ecological environment".

It is clear that the highest-level legal instrument in the land addresses itself specifically to the development of both a Smart Grid policy and a sustainable Renewables policy.

Turning to the subject of the reliability and security of the electrical system, Article 40, point 2, paragraph a) of the Electricity Law mandates the following obligations for energy transmission activities: "*a) To ensure the safe, stable and reliable operation of the electricity grids and electricity transmitting equipment.*"

The same Article and point establishes that the obligation of the Transmission operator is progressive and far reaching "…to draw up plans for investment in development of the electricity transmission grids and invest in the development of electricity transmission grids to satisfy the electricity transmission demands under the electricity development planning; to invest electricity-measuring or -counting equipment as well as support equipment…."

Thus, the mandates of the Electricity Law provide more than enough grounds for the development of a Smart Grid by NPT, the legally nominated transmission operator. It is recommended that the NPT's plan include the Smart Grid applications with a positive cost-benefit analysis in order to develop a reliable network and apply "technological advances" as required by the Law.

The regulatory body (ERAV) is responsible for the analysis, approval and oversight[10] [8] of the investments that the transmission operator (NPT) has to make in order to comply with the legally binding requirement to prevent both sustained interruptions and major events (blackouts).

F.3.1 Decree No. 137/2013/ND-CP

This Decree details the implementation of several articles of the Electricity Law regarding planning and investment in electricity development. It addresses many aspects of electrical power from the management of demand, sales and purchases, prices, activity licenses, regulation and inspection activities to usage.

According to this Decision, the Ministry of Industry and Trade is responsible for the planning of electricity development, guidance on planning annual electricity investment and for development on the basis of the approved plan for electricity development.

The Ministry is also responsible for announcing the national master plan on electricity development, including the amended master plans that have already been approved.

Article 5 of this Decision establishes the demarcation limits for the construction of a transmission infrastructure. This Article decrees that the transmission and distribution companies are responsible for investment in the construction of switching stations, substations, stations for reactive power compensation within their management remit, unless otherwise agreed. This means they are responsible for enhancing the transmission network using, if they wish, Smart Grid technology (according to Article 4 of the Electricity Law).

Article 6 of the Decision establishes that the power lines, transmission substations and new power distribution stations must be designed with and use technical equipment and technologies in line with technical regulations and national standards (Vietnam's standards), or foreign standards which are equivalent or higher and are permitted by competent state agencies for application in Vietnam.

Article 6 also establishes that transmission companies are responsible for building plans, roadmaps for renovations, current line upgrades, transmission substations and power distribution stations compliant with national or comparable international technical regulations and standards.

Article 15 defines some qualitative standards and benchmarks for the voltage and frequency of the electric system:

a. "About voltage: In normal conditions, the permitted difference of voltage is about ± 5% in comparison with the nominal voltage of the power grid and defined at positions where equipment for electricity metering is laid or other positions as agreed by two parties. For a power grid which has not stabilized to a steady state following an incident, the permitted difference of voltage is from +5% to -10%;

b. About frequency: In normal conditions, the permitted frequency difference of the electrical system is about ± 0,2Hz in comparison with nominal frequency of 50Hz. For a power grid which has stabilized to a steady state following an incident, the permitted frequency difference is ± 0,5Hz".

The Article finishes by establishing a market for reactive power when $\cos \varphi < 0.9$.

On the other hand, Article 22 addresses the sale and purchase of electricity to/from foreign countries. It states that those authorized as competent to permit the sale and purchase of electricity with foreign countries include:

a. The Prime Minister who shall approve policies for the sale and purchase of electricity with foreign countries through the national power grid at a voltage of 220 kV or more. The Ministry of Industry and Trade shall consider proposals for the sale and/or purchase of electricity with foreign countries measured in electricity units, and submit them to the Prime Minister;

b. The Ministry of Industry and Trade shall approve policies for the sale and purchase of electricity with foreign countries through the national power grid at voltages of less than 220 kV measured in electricity units.

Articles 5 and 6 of the Decision clearly allocate the responsibility for investment in Smart Grid technology to the transmission companies. This emphasizes the general policy established in the Electricity Law.

F.4 Regulatory Framework

In order to have a complete overview of the regulatory framework it is important to review the Decisions of the Ministry and the Regulatory Authority regarding the security and reliability of service (prevention of blackouts), the long-term planning of the transmission network (Smart Grid), the Decisions mentioned in the Vietnamese Roadmap as well as those regarding the regulation of frequency and others identified in the Task-1 Report.

F.4.1 Grid Code

The Grid Code has 13 chapters and the main ones relevant to this study are as follows:

a. Chapter III—Power System Performance Standards;

b. Chapter V—Network Planning;

c. Chapter VI—Power System Operation; and

d. Chapter IX—Performance Indicators.

F.4.1.1 Chapter III - Power System Performance Standards

Chapter III lays out the power quality performance standards that the System Operator and Transmission Network Operator are aiming for when operating the power system.

Article 19 defines the System Frequency and the upper and lower limits, and Article 53 details the requirements of the power plant governors. Nevertheless the Grid Code does not mention anything regarding the secondary and tertiary regulation and the limits established for the frequency of these aspects. It is worth highlighting the importance of having a rigorous frequency regulation for the power system. This includes the generation units as well as the primary, secondary and tertiary systems.

The Grid Code is lacking on this important aspect and must be complemented. This will also enable one of the basic pillars presented in the Task-1 Report.

This chapter also establishes the Reliability Standards and the annual target in MWh defined by the regulating authority (ERAV) for the annual un-served energy.

According to Article 22, in order to establish an annual target ERAV shall i) consult with the Transmission Network Operator (TNO), System Operator (SO) and all Users; ii) seek advice from the TNO on any impact on transmission costs of a proposed target; and iii) give due consideration to the costs and quality of supply preferences of all Users.

It is recommended that ERAV ask for a cost-benefit analysis in order to improve the MWh target of un-served energy instead of guidance on cost levels. The decision has to be taken by the regulatory body for the overall electricity system taking account of the willingness of the users to pay and the Value of Lost Load (VoLL).

The setting of this regulatory target as a part of the Reliability Standards is a key point to incentivize the development of Smart Grid technologies in order to improve the yearly MWh not served in order to reduce the regular transmission outages and major events such as blackouts. Without this target, there is neither the pressure nor incentive for the TNO to implement a more aggressive policy in order to solve the existing problems and improve the reliability of the system.

Article 25 of the Code establishes the maximum Short Circuit Current and Fault Clearance Times. The maximum short circuit current for the 500 kV and 220 kV is 40 kA. This value should be updated for some substations in order to support higher currents (50 kA) in some parts of the network. This will lend support to the argument in favor of the technology for the "pillars" as defined in Task-1, which will enable Network Planning to limit these values.

One of the important topics to consider is voltage dips. The common cause of this phenomenon is temporary, intermittent loss of supply typically caused by short circuits, load switching, network switching and power swings. These phenomena have a significant impact on the operation of industry, manufacturing and mining plant machinery, which depends on a steady, consistent power supply. Dips in the supply voltage (depressions in supply voltage of short duration) can lead to unnecessary stoppage of plant processes unless adequate measures have been taken in the design of their electrical equipment.

Given the current status of industrial development in Vietnam as well as the concerns of the Industrial Zones Management Authority [9] for the 800 industries, there is an urgent need to improve the overall quality of service by addressing the issue of voltage dips in the Grid Code.

The recommendation is to complement the quality of performance of the Grid Code regarding voltage dips in order to avoid interrupting power supply to the manufacturing industry. Smart Grid technology solutions have been used in other countries to successfully reduce or even eliminate voltage dips.

F.4.1.2 Chapter V - Network Planning

According to Article 77, the TNO is responsible for investment in the transmission network to:

a. Support the current approved national power development plan, regional power development plan as well as any current connection contracts;

b. Meet the network performance criteria in Articles 22 to 33.

The provisions established in the Grid code allow the TNO to invest in sustaining performance levels of:

a. Reliability Standards;

b. System Loss Standards;

c. Voltage Unbalance;

d. Short Circuit Current and Fault Clearance Time;

e. Harmonics;

f. Voltage Fluctuations and Flicker Severity;

g. Ground Fault Factor;

h. Neutral Grounding; and

i. System Voltage.

The regulation allows the TNO to invest in Smart Grid technologies in order to maintain the standards and avoid the problems mentioned above. These investments are in addition to the Approved National Power Development Plan. The requirement is approved by the regulatory authority (ERAV).

F.4.1.3 Chapter VI - Power System Operation

The operational issues, responsibilities and obligations of the System Operator (NLDC) are clearly described in this chapter.

Article 92 establishes that the System Operator is responsible for providing security constrained economic dispatch. Further, Article 112 mentions the security constraints to be considered while ensuring economic dispatch.

In Chapter VIII – An Outage Planning Process is mandated to ensure that the security of supply can be maintained throughout the two years and for the following 12 months. The Outage Planning Process will be achieved by conducting medium and short-term security assessments.

The Grid Code defines System Security Assessment as a "process, based on available data and information, to analyze and announce the total projected usable capacity and load together with system security requirements in the medium and short term."

Nevertheless, one of the most important components missing from this assessment is on-line security. In order to perform the task required by Article 92, on-line security is a fundamental requirement. This topic was fully addressed in the "pillars" in the Task-1 Report.

In addition, what is missing from the Grid Code regulation is the obligation of the System Operator to have the proper tools in order to evaluate all the parameters as well as perform on-line monitoring and control of the voltage/dynamic stability of the Vietnamese Power System.

A complementary point in this chapter will help the System Operator to acquire the most up-to date technology in order to properly monitor and control the operation of the electrical system.

This will also facilitate the introduction of Smart Grid technologies like WAMS and all the associated applications.

F.4.1.4 Chapter IX - Performance Indicators

This chapter of the Grid Code presents the performance indicators that apply to the System Operator (7) and to the TNO (6 groups).

It is worth highlighting that the indicators proposed require declaring the un-served energy for each unplanned event as well as the total number of unplanned interruptions in excess of 1 minute.

Nevertheless, these indicators do not take account of using the appropriate methods or tools to investigate the causes that led to a blackout. It is not adequate to state that the cause of the blackout was a tree falling across a transmission line or a tripped relay. It is important to assess how the original event led to a significant system wide black-out and properly diagnose the power system phenomena that are involved in the knock-on effect that causes a single, relatively trivial, event to propagate across the system. Once identified these single points of failure have to be eliminated with appropriate investment and commensurate procedures and practices.

The indicators of unplanned interruptions must be investigated to discover the real causes of a blackout (voltage collapse, transient instability, etc.) so as to determine what measurements and measures the TNO could have taken in advance in order to prevent those interruptions.

From the interviews performed in Vietnam is clear that both the SO and the TNO do not have the proper tools in order to either trace the real causes of an event or to prevent it.

F.4.2 Smart Grid Roadmap

The Vietnamese government issued Decision No.: 1670QĐ-TTg in November 2012 approving a national Smart Grid development.

The Decision specifies both general and specific targets for the Smart Grid roadmap:

a. General target: Develop a Smart grid with high technology support in order to improve the quality and reliability of the national power supply; contribute demand side management, encourage energy saving measures and efficiency; create favorable conditions for the improvement of labor productivity, reduction of investment demand on generation and power network; enhance the rational exploitation of energy resources, ensure national energy security, contribute to environmental protection and sustainable socioeconomic development.

b. Specific Target: the list of Smart Grid initiatives mentioned in the preceding sections.

The Decision establishes the general target but without mentioning the specific legal support for the Decision such as particular articles of the law and the regulatory framework.

The Decision also does not consider the incentive mechanism, the remuneration for those initiatives, the cost-benefit analysis or the metrics for each initiative.

F.4.3 Decision on Renewables

F.4.3.1 Decision No. 37/2011/QD-TTg

Decision No. 37/2011/QD-TTg on 29 June 2011 focuses on the development of Wind Power Projects in Vietnam.

The Decision emphasized the planning mechanisms and processes of wind power projects rather than incentives to promote wind power generation.

Article 4 of the Decision establishes that The Ministry of Industry and Trade organizes the planning for wind power development, which is then submitted to The Prime Minister for approval. The Prime Minister's office is also responsible for announcing, monitoring and controlling the execution of the approved national plans for wind power development.

The People's Committee of those centrally-affiliated cities that have a potential for wind power development are tasked with organizing the planning of wind power development at a provincial level and to then submit their proposals to the Minister of Industry and Trade for approval.

The investors in Wind power projects that are not on the list of nationally approved wind power development schemes are responsible for submitting proposals on supplementary systems to the Ministry of Industry and Trade who will evaluate and submit them to The Prime Minister's office for consideration and final decision.

Article 7 of this Decision states that the connection of Wind power projects to the national electricity grid must be part of the approved plan for development. The connection point is agreed by both the electricity seller and purchaser on the understanding that the electricity seller has the responsibility for investment in the transmission line/s to the connection point/s of the national electricity grid which should be the nearest to the planned site for the provincial electricity development.

The mechanism for supporting wind generation (Article 11) states that the electricity purchaser is responsible for the wholesale purchase of the electricity produced from grid-linked wind power plants in a given area. Electricity trading is performed through a typical electricity trade contract overseen by the Ministry of Trade and Industry and is based on the following:

a. Contract Period of twenty years from the commencement date of the trading operation. The electricity seller may extend the contract period or sign a new contract with the electricity purchaser according to the regulations.

b. The Base Price for purchasing electricity and the principle for adjusting the Price of selling electricity at contract renewal time.

c. Agreement regarding connection, measurement and operation of the wind power plant.

Wind power projects enjoy preferential import tax relief as well as preferential enterprise income tax relief. Wind power projects are exempt from import tax for goods and have a reduced enterprise income tax.

Article 14 establishes a price for grid-tied wind power projects. The electricity buyer has responsibility for buying output from wind power projects at the point of electricity receipt at a wholesale rate of 7.8 $cents/kWh or its equivalent of 1.614 Dong/kWh (without VAT). The electricity purchase price is adjusted by the current exchange rate between the Dong and $. The government of Vietnam supports the electricity price for the buyer of wind power generated power at the rate of 207 Dong/kwh (equivalence 1.0 $cents/kWh) through the Vietnam Fund for Environment Protection.

The final price, subsidized by the government, is 6.8 $cents/kWh while the average approved electricity tariff is approximately 7.6 $cents/kWh (1,509 Dong/kwh) [10]. According to the Asian Development Bank the tariff of 1,500 Dong/kwh is lower than the long-run marginal cost estimated to be in the range of 1,7001,900 Dong/kwh.

These positive aspects are designed to encourage the introduction of energy generation from renewable sources in Vietnam and are intended to act as an incentive for their development. The less attractive aspect is that the agreement is always based on a typical contract and the final decision probably lies, yet again, with the Ministry.

Further, the planning mechanisms and approval cycles are controlled by the Prime Minister's office and the Ministry of Industry and Trade. This arrangement requires more flexibility in the market environment in order to avoid bottlenecks.

The regulations require that the wind farm must be connected to the grid at the closest transmission grid connection point. The incentives for wind power generation motivate the investor to ensure that the grid connection point is reliable and this acts as an indirect spur to investments in more advanced technologies like the Smart Grid initiatives.

F.4.4 An overview of the Power Master Plan VII

On July 21, 2011 through Decision No. 1208/QD-TTg, the Prime Minister approved the seventh power development plan for the period 2011 to 2020 with a view towards 2030 (the Power Master Plan VII/MP VII). The Plan is based on the assumption of GDP growth at 7 to 8% during the period 2011 to 2030 and the expectation that electricity demand will grow by 12.1% per year (worst-case scenario), 13.4% per year (base-case scenario) or 16.1% per year (best-case scenario). MP VII emphasized four main areas:

a. The development of power sources (priority for renewable energy development);
b. The development of the power transmission grid (efficient use of energy - i.e. Smart Grid technologies);
c. Interconnection of power networks with neighboring countries; and
d. Electricity supply to rural, mountainous and island areas.

The Plan emphasized a balanced development of power sources in each region of Vietnam (North, Central and South) to ensure the power reserve capacity is evenly shared and reliable for each region. According to the Plan, the aggregate power generation capacity of all the power plants in Vietnam will increase to about 75,000 MW by 2020 (with produced and imported electricity of 330 billion kWh) and 146,800 MW by 2030 (with produced and imported electricity of 695 billion kWh).

According to the plan, fossil fuel will be the most important source of electricity in Vietnam in the medium and long-term. Power generation capacity from this source will rise from 21,000 MW in 2010 (which saw the production of 100 billion kWh) to 36,000 MW in 2020 (predicted ~156 billion kWh output) and to 75,000 MW in 2030 (predicted ~394 billion kWh output). As the current domestic coal supply is insufficient, importing coal from nearby countries is accelerating and new coal-fired generation plants using imported coal are required to start operating from 2015.

MP VII also gives top priority to the development of power sources using renewable energy such as wind, solar and biomass power. The percentage of renewable energy power is projected to increase from almost zero to 5.6% by 2020 and 9.4% by 2030. The Plan aims to increase the combined capacity of all wind power plants to about 1,000 MW by 2020 and 6,200 MW by 2030 to raise the percentage of wind power to 0.7% by 2020 and 2.4% by 2030. Further, Vietnam encourages the development of multi-functioned hydropower projects (flood control, water supply and power production) and the total capacity of hydropower plants is anticipated to reach 19,125 MW by 2020.

The development guidelines include two keynotes as follows;

a. Investing more in the national power transmission grids in order to bring more power plants online combined with an the overall development strategy for the power sectors and regions;

b. Increasing the reliability of power supply, reducing power loss and ensuring a favorable mobilization of power sources between rainy and dry seasons and in all operation regimes of the power market.

According to the plan, the voltage level of 500 kV will still be the dominant superhigh voltage for power transmission of Vietnam. There is a plan for further research on the development of transmission networks at voltage levels of 750 kV, 1000 kV and by high voltage direct current transmission systems after 2020.

The Master Plan also establishes that grid modernization should be performed gradually. The renovation and upgrading of switchgear, protection and automation of the grid, research on using FACTS, SVC devices to increase the transmission limits and a step-by-step modernizing of the control systems. MP VII also references the research on developing "Smart Grid" technology, making the interaction between household consumption, industrial equipment and the electricity grid capable of exploiting the most effective approach to energy supply while reducing the cost of grid development and improving the security of the power supply.

MP VII places some emphasis on thermal coal-fired power development and renewables. The plan references Smart Grid technology in the context of modernizing the grid with a focus on research of FACTS, SVC and other technologies in order to improve the security of power supply.

F.4.5 Electricity Market Roadmap

Decision No. 63/2013/QD-TTg, dated 8 November 2013, made by the Prime Minister's office, presents an Electricity Market Roadmap defining the conditions and structure of the electricity generation and transmission system to shape and develop the electricity market in Vietnam.

The Decision defines a three phase gradual approach as follows:

a. Phase 1: Vietnam Competitive Generation Market (VCGM). Requires that competitive power generation be continued until the end of 2014;

b. Phase 2: Vietnam Competitive Wholesale Market (VCWM). This phase will be implemented in two steps; first as a pilot competitive wholesale market from 2015 to 2016 rolling over to a full competitive wholesale market from 2017 to 2021;

c. Phase 3: Vietnam Competitive Retail Market (VCRM). This phase will also be implemented in two steps; first as a pilot competitive retail power market from 2022 to 2023 rolling over to a full competitive retail power market from 2024 onwards.

In order to form the Vietnam Competitive Wholesale Market, the power sector structure must satisfy the two following conditions:

a. Firstly, during the pilot wholesale market phase, the National Load Dispatch Center and Power market administrator must be kept as independent units that have no common interests with stakeholders participating in the power market.

   The Power Generation Corporation and power plants under the Electricity of Vietnam (except for big power plants that have special roles in supporting the local economy, national defense and security, which are managed by the State's monopoly as stipulated in Article 4 of the Electricity Law) shall be split into independent power generation units which have no common interests with bulk power units or with transmission units. The National Load Dispatch Center will act as the Power market's transaction administrator.

   The total installed capacity of a power generation unit shall not exceed 25% of total installed capacity of units participating in the Power market.

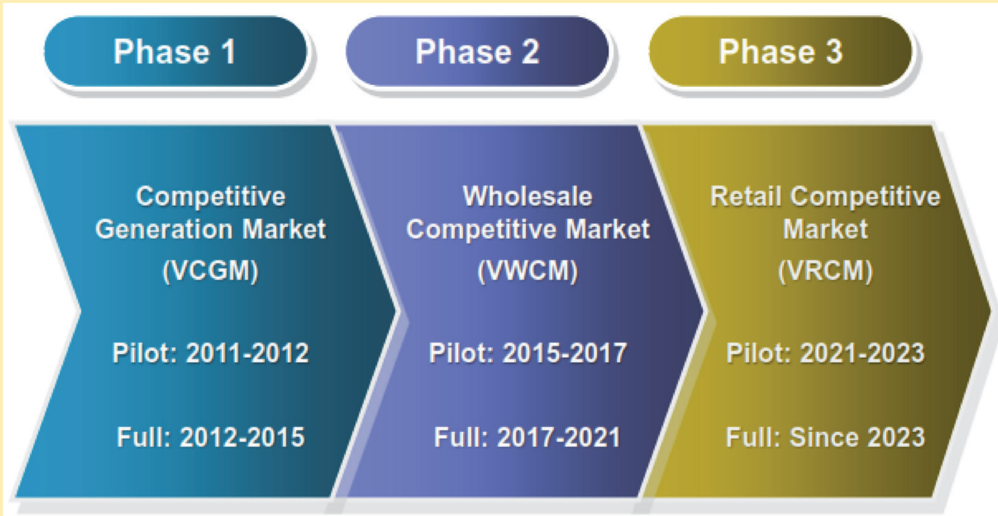
   The Power Corporations and the Power Companies, which satisfy the aforementioned conditions, will be selected for participation in the pilot and full wholesale market. There must be a clear demarcation between the organizational and cost-accounting functions of the power distribution and the power retail units.

b. Secondly, in the full competitive market, Power companies under the Power corporations should be organized into independent cost-accounting units, which must be demonstrably separated from the cost-accounting functions of the power distribution and the power retail departments.

In order to form a competitive retail market, the power sector structure is required to satisfy the two following conditions:

a. During the pilot phase for a competitive retail market, retail departments of several Power companies, which satisfy conditions for participation in the pilot competitive retail market as stipulated

FIGURE 116: MARKET ROADMAP PHASES



Source: Authors

must be split into independent cost-accounting power retail units.

b. In the full power retail market, the retail departments of the power corporation shall be split into independent cost-accounting retailers.

The market roadmap is shown summarized in Figure 116. It has been and will continue be executed by ERAV [11]. The Pilot VCGM was launched on July 1, 2011 and the Full VCGM was launched on July 1, 2012 with the participation of electricity generators representing approximately 35% of the total installed capacity of the national system.

The details of the VCWM, the Market rules and the Market infrastructures are expected to be completed in 2015. The expansion of competition at the wholesale level (VCWM), which will allow generators to sell electricity to multiple wholesale purchasers, including PCs and qualified large customers is also expected in 2015.

F.4.6 Organizational Structure of Regulator

The Prime Minister issued Decision No. 153/2008/QD-TTg on November 28th, 2008 to define the functions, duties, authority and organizational structure of the Electricity Regulatory Authority under the Ministry of Industry and Trade (MOIT).

This requires the Electricity Regulation Bureau to advise the Ministry of Industry and Trade on regulations for the safe, stable and secure operation of the electricity generation infrastructure combined with the use of electricity-saving and effective equipment.

The Authority's duties, includes submissions to the Industry and Trade Minister in order to approve or issue regulations as well as to establish electricity prices from the Government and the Prime Minister. It also includes submissions to the Minister of Industry and Trade to approve or promulgate conditions, orders, procedures, appraisals and approval of the minimum cost plan, as well as regulations on the condition and order to stop power supply.

The Authority's regulatory duties of the electricity market includes appraisal of power development in provinces and cities, publicizing lists of transmission grid resource projects according to the approved plans, supervising the planning of electricity resource development investment projects, transmission grids, general repair and maintenance, supplementing or withdrawing power operation licenses, issuing electricity price frameworks, setting transmission prices and the cost of using support services.

The regulatory Authority is one of the key stakeholders in the Smart Grid initiatives in Vietnam and has encouraged the cost-benefit analysis for each of them in order to foster the Vietnamese Competitive Wholesale Market.

F.5 Topics that Impact the Regulation of Smart Grids

In order to perform a review of the regulatory framework under the ambit of Smart Grids, the following areas have been identified and analyzed (Figure 117):

a. System Security policy;
b. Renewables and their policies and incentives;
c. International Interconnection policy;
d. Quality of Service regulatory policy (indicators, incentives, penalties);
e. Smart Grid Policy; and
f. General policy for investment incentive in transmission and recovery mechanism.

The following will analyze the general impact that each policy may have on the Vietnamese Smart Grid policy.

F.5.1 System Security Policy

The System Security Policy was introduced in Chapter VII of the Grid Code and analyzed in this document. Article 92 of the Grid Code establishes that the System Operator is responsible for undertaking security constrained economic dispatch. Further, Article 112 mentions the security constraints to be considered in the economic dispatch.

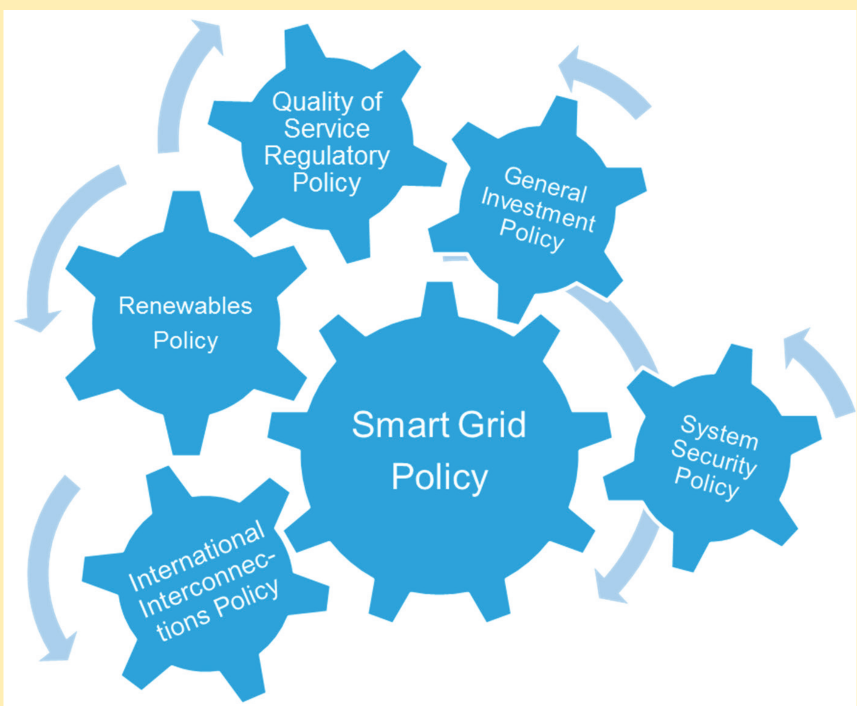
Chapter VIII – The Outage Planning Process also establishes the requirement to perform medium and short-term security assessments to ensure that the security of supply can be maintained throughout the two years and the following 12 months.

Nevertheless, an important missing component is on-line security assessment. In order to avoid repeating past errors it is important to introduce an on-line security assessment process. This topic was properly addressed in the "pillars" in the Task-1 Report.

As mentioned before, the Grid Code requires the System Operator to have the appropriate tools in order to evaluate the security and perform on-line monitoring as well as having on-line control of the voltage/dynamic stability of the Vietnamese Power System.

MP VII mentions the modernization of the grid and encourages research of FACTS, SVC and other technologies in order to improve the security of power supply.

FIGURE 117: POLICIES THAT IMPACT SMART GRIDS



Source: Authors

Finally, Decision No. 1670QĐ-TTg for the Smart Grids Roadmap (November 2012) specifies in the General targets: "Develop Smart grid with support of high technology in order to improve quality and reliability of power supply…."

According to the previous framework and considering the frequency of the outage events suffered in Vietnam including blackouts, it is advisable to develop a separate Policy in order to better guide the transmission authority's investments in Smart Grid technologies.

This policy will have an important effect on the development of both the network and Smart Grid technologies as well as having an important impact at an external level on enhancing the security and reliability of the system in order to sustain the country's industrial development. It will also have the additional benefit of attracting new industrial investments as reported to Bloomberg by many sources from the Industrial Zones Management Authority [9] [12] [13].

F.5.2 Renewable Energy Policy

The renewables and their incentives policy is one of the most important topics that affect the Smart Grid initiatives and their development. A strong policy that incentivizes the development of renewable power sources (larger plants rather than domestic rooftop installations for example) will increase penetration of renewable resources and will have a significant impact on the performance and reliability of the electricity grid.

The current inefficiencies of renewable power sources are largely due to their inherent variability compounded by the lack of large-scale economical storage capability.

Traditional planning for a power system and for expanding transmission functions has been undertaken in response to the needs of the transmission system based mainly on past and projected loading levels, which have traditionally been estimates of future demand.

In a market environment, and in the present case of using different renewable energy sources (i.e., Differences in source and temporal characteristics, as well as in geographic location), transmission planning must respond to the needs of adequate reserve capacity in order to facilitate the penetration of renewable sources.

Vietnam is aiming for a full-deregulation of their wholesale market and the renewables policy is one of the main topics that needs further attention. The Smart Grid initiatives and their policies will be significantly impacted by the introduction of renewable sources.

According to paragraph 4 of Article 4 of the Electricity Law No. 28/2004/QH11, one of the Electricity Development policies is to "step up the exploitation and use of sources of new energies, renewable energy for electricity generation" and one of the measures to encourage and promote energy savings is by "Providing investment, electricity price and tax preferences as guided by the Finance Ministry to investment projects on development of power plants using sources or new energy or renewable energy".

Article 29 of the Electricity Law also establishes the Electricity Price Policies and the creation of "conditions for various economic sectors to invest in electricity development with reasonable profits, energy resource saving, the use of various new energy, renewable energy".

From the previous regulation it is clear that the Electricity Law has several general provisions aimed at fostering a Renewable Energy Policy. These provisions set a policy mechanism that supports the development of renewable energy and are quite well established in the context of the Kelsen pyramid.

Decisions about the development of renewables are primarily focused on wind and biomass policies. The criteria, methodologies and incentives established concentrate on planning procedures rather than on fostering and assessing renewable energy investments. It is recommended that the renewable policy for Smart Grid applications of the refined roadmap is augmented to support the integration of renewables in the transmission network.

F.5.3 International Interconnection policy

International Interconnections are addressed in Article 2 of the Electricity Law which states that "This Law applies to organizations and individuals conducting electricity activities, using electricity or engaged in other electricity-related activities in Vietnam. Where the international treaties which the Socialist Republic of Vietnam has signed or acceded to contain provisions different from provisions of this Law, the provisions of such international treaties shall apply".

The Law includes a provision that the treaties will prevail over the established in the law. This means that any treaty for an international interconnection with different conditions to those established in the Law may be applied. This introduces flexibility in order to perform international interconnections but, on the other hand, it generates potential advantages and disadvantages for the electricity market participants. International treaties may favor a specific participant in comparison to the others, affecting regular operation and dispatching in the market.

Article 22 of Decree No. 137/2013/ND-CP addresses the sale and purchase of electricity from/to foreign countries. It also identifies the authority competent to permit the commercial trade in electricity with foreign countries:

a. The Prime Minister who shall approve policies for the sale and purchase of electricity with foreign countries through the national power grid at voltages of 220 kV or more. The Ministry of Industry and Trade shall consider proposals for the sale and purchase of electricity with foreign countries and submit them to the Prime Minister;

b. The Ministry of Industry and Trade shall approve policies of the sale and purchase of electricity with foreign countries through the national power grid at voltages of less than 220 kV at the request of electricity business units.

No other provisions were found that could be applied to international interconnections, except for those quoted above.

A clearer policy direction is needed regarding international interconnections and this may have some significance for the development and deployment of some of the Smart Grid initiatives, e.g., HVDC interconnection and more stringent requirements for online monitoring and security assessment to ensure frequency/voltage problems do not cascade from one system to another, etc. A policy that addresses these points may facilitate the inclusion of technologies like HVDC and to increase the use of SVC technology for maintaining the stability of the systems and link.

F.5.4 Quality of Service Policy

In general, all the legislation that creates a de-regulated environment or introduces a market environment is essentially dealing with quality of service issues. This is a consequence of the economic and regulatory theory that in order to control the quality of a product (electricity), one must control the quality of the technical and commercial services that support it.

The most unambiguous signals of a quality of service policy are effective mechanisms for incentives and/or penalties.

The Vietnamese Electricity Law does not establish penalties or incentives for the quality of service.

The revision of the Grid Code also indicates that they do not have penalties for quality of service.

The lack of penalties for the TNO weakens the case for the introduction of Smart Grid technologies, which are being pushed (as presented in many references in Task-2) by the industrial user community who have a poor perception of the quality of service of electricity supplies.

F.5.5 Smart Grid Policy

Article 4, paragraph 3 of the Electricity Law No. 28/2004/QH11[11], establishes the Electricity Development policies: "apply scientific and technological advances to electricity activities and use with a view to saving, raising the efficiency of using various energy sources, protecting the ecological environment".

This principle established by Law can be applied in order to properly develop a Smart Grid policy, which takes into consideration not only the criteria for development but also the mechanisms i.e. the incentives and the remuneration of the Smart Grid applications to be developed in the country.

As previously mentioned Decision No.: 1670QĐ-TTg in November 2012 does not reference any remuneration and incentive mechanisms, penalties, cost-benefit analyses or any KPIs in order to track performance.

Given the existing regulations governing the Smart Grid roadmap and the provisions of Article 4 of the Electricity Law, it is recommended that the Smart Grid development be augmented by the following:

a. The design of an incentive mechanism;

b. The cost-benefit analysis of the initiative;

c. The metrics for each initiative; and

d. Penalties for significant brownouts and blackouts in the electricity system.

This mechanism should not simply provide the TNO with cost recovery for their approved Smart Grid investments but rather to add basis points that fundamentally incentivize utilities to invest in innovation.

The Vietnamese policy makers may want to take inspiration from IRENA in the development of a policy that takes into account:

a. Effective support must be comprehensive and sustained and designed to minimize investment risks;

b. The effective support for policy development has been performed in this study;

c. Effective and efficient support must balance stability with adaptability;

d. Stability is vital for creating investor confidence in support mechanisms, otherwise, investments may fail to take place or be more expensive due to higher risks. Nevertheless, policies must be able to adapt to changing circumstances and respond to as many signs from the investors as possible;

e. Desired equity impacts can be achieved through sound policy design. This evaluation was performed with the cost-benefit analysis presented in Task-2 and helped to identify equity impacts and opportunities for improvement;

f. Assessing institutional feasibility can inform policy choices;

g. In order for a policy to operate successfully countries must have the requisite capacity to implement any given policy tool. Evaluations of institutional feasibility can help inform the choice of policy tool and the investments that are needed to enlarge policy options;

h. Evaluating replicability can help tailor policies to country conditions; and

i. Some factors that have led to success in one country may not be present in another. This type of analysis can help identify investment policy adaptations that are important for good performance. It can also help set realistic expectations of policy outcomes.

F.5.6 General policy for investment incentive in transmission and recovery mechanism

According to the structure of the Electricity sector, the Directorate General of Energy (DGE) under the MOIT is responsible for energy planning and policy.

The Master Plan created by the Ministry of Industry and Trade references development guidelines for transmission networks and includes two key notes [14]:

a. Investing more in the national power transmission grids that will allow power plants to be brought on-line, within the overall development strategy of power sectors and regions;

b. Increasing the reliability of power supplies, reducing power loss and ensuring a favorable mobilization of power sources between rainy and dry seasons and in all operational regimes of the power market.

Further, Article 6 of Decree No. 137/2013/ND-CP states that transmission companies are responsible for building plans, roadmaps for renovating, for upgrading the existing lines, building transmission substations and power distribution stations in order to ensure compliance with technical regulations and either national standards or comparable foreign standards.

General policy for investment incentives in transmission and recovery mechanisms is established according to the legal framework. The approval of investments in Smart Grids or any other transmission initiatives is performed by ERAV according to the Electricity Law and the current regulations.

The recovery mechanism for such investments is also established in Article 31, second paragraph of the Electricity Law as follows:

> "The electricity generation prices, electricity-wholesaling prices and charges for electricity transmission, distribution, electric-system regulation, electricity market transaction administration, support service expenses shall be formulated by the concerned electricity units and appraised by the electricity-regulating agency before they are submitted to the Industry Minister for approval".

Circular No. 14/2010/TT-BCT from 15th of May 2010 describes the detailed mechanism to define the transmission process as well as the recovery of the transmission investments. The Circular clearly establishes that each year, according to the principle of ensuring full cost recovery and permitted profits, the operator must run the transmission grid according to the quality regulations and to meet key financial targets for the investment and development of the transmission grid.

A positive cost-benefit ratio is the most effective means of ensuring cost recovery of Smart Grid investments in transmission. The regulator will be able to approve the cost recovery under the current mechanism without any change or amendment to the current regulatory framework.

F.6 Recommendations for Implementation

The willing and active participation of the main stakeholders is imperative to ensure a successful implementation of the Refined Roadmap. The stakeholders identified as the main participants in the Refined Roadmap implementation are the following:

a. ERAV;

b. NPT;

c. NLDC; and

d. IE.

The regulatory body has the lead role in approving the Refined Roadmap and enforcing its application. NPT and NLDC are major influencers particularly from a technical and economic perspective.

Each stakeholder has two dimensions to their role in the approval and execution of the roadmap:

a. Commitment; and

b. Role and Importance of the Stakeholder to Success.

The importance of the NPT to the ultimate success of the Smart Grid initiatives makes it imperative to increase their actual commitment. However, the perceived commitment of middle management is also considered relevant to the overall success of the Smart Grid initiatives.

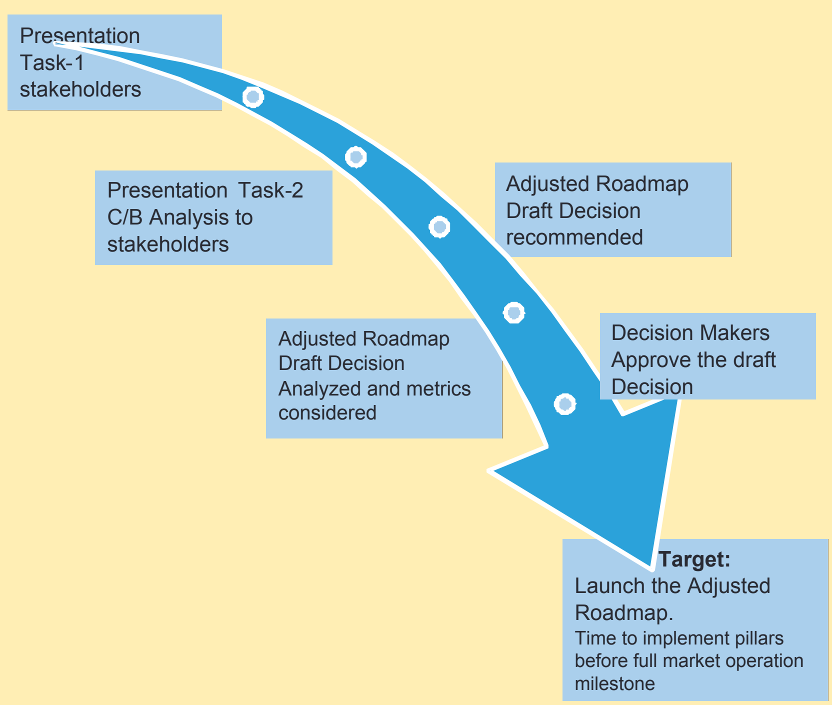
The NLDC who are major influencers have an important role in the implementation of some Smart Grid recommended applications and it essential that they be encouraged to take a more active role in the process.

Finally, as analyzed in the previous chapters, the Electricity Law provides a basic legal framework in order to introduce new technologies (Smart Grid initiatives) in the power system. These legal provisions in the Electricity Law will be adequate to foster the development of Smart Grid technologies in a market environment consisting of an experienced and mature electrical sector.

Given the approved Roadmap, the perceptions from the workshops and interviews and the consultant's experience in similar cases, the manner in which the Smart Grid initiatives have been introduced in Vietnam, i.e. by Government Decision, is the most appropriate and indeed the recommended approach.

For this reason, is important to complement this Decision with a detailed policy in order to establish clear economic and technical advantages that can bring about increased benefits and performance. It is also recommended that a Smart Grid Committee be created to both oversee and ensure the success of the Smart Grid initiatives. This approach (Figure 118) will do much to reduce the risks associated with the introduction of new technologies and smooth the way through the multi-layered approvals process.

FIGURE 118: REFINED ROADMAP MILESTONES FOR IMPLEMENTATION



Source: Authors

A draft of the refined roadmap is presented in Annex 1, which retains the same approach of the previous decisions and avoids changes in style or the introduction of new elements, such as the support Articles of the Law and the technical and economic reasons to introduce the changes to the policy.

The expected milestones in the implementation are presented in Figure 118. The success depends on the commitment of the stakeholders and the possible pressure that can be brought to bear by the government and institutions.

The Refined Decision should also consider the "pillars" in order to enhance the electrical system for a robust Smart Grid implementation as well as the full operation of the electricity market, a milestone to be achieved in 2016.

Additionally, a Decision for approving the KPIs which will control and monitor the Smart Grid initiatives is also required. It is recommended that the approval of the KPIs is achieved independently from the Decision of the Refined Roadmap so that ERAV will have the flexibility to change these values (if required) without having to issue a new Decision of the Roadmap for each change.

F.6.1 Roles and Responsibilities

In order to implement the Refined Roadmap, each institution has an important role to ensure the successful implementation of the program. The following matrix presents the activities to be performed during the implementation process. The responsibility assignment matrix known as a RACI matrix describes the participation by various roles in completing tasks or deliverables for the implementation of the Smart Grid program.

The RACI meanings and roles are as follows;

a. **Responsible (R)**: This is assigned to the individual/s who perform the work to achieve the task. For each initiative there will be at least on individual assigned as 'R' though others may be delegated to assist in the work required.

b. **Accountable (A)** (also approver or final approving authority): This is assigned to the individual ultimately answerable for the prompt and successful completion of the deliverable or task. The assignee 'A' will also nominate the individual responsible, 'R', for the performance of the task/s. The assignee 'A' must approve the work that responsible 'R' delivers. There must be only one individual assigned as accountable for each specified task or deliverable.

c. **Consulted (C)**: Those whose opinions are sought, typically subject matter experts, and with whom there is two-way communication.

d. **Informed (I)**: Those who are kept up-to-date on progress, often only upon completion of the task or deliverable and with whom there is just typically one-way communication.

The main activities associated with the implementation of the refined roadmap are identified and described in Table 82.

TABLE 82: RACI MATRIX FOR THE ROLES AND RESPONSIBILITIES OF THE REFINED ROADMAP

Activity	NPT	NLDC	ERAV	IE
Internally approve the Refined Roadmap	R	R		
Present the Final Report to other institutions	R	I	I	I
Define the priorities for Implementation in the short-term	R	R	A	
Request approval of the Refined Roadmap to regulator	R	R	A	
Approve the Refined Roadmap and the Smart Grid initiatives in the short, medium and long term	C	C	R	I
Based on the recommended KPIs, define the final targets for the KPI for the implementation	C	C	R	
Include the approved investments in the Master Plan	CA	CI	I	R
Follow up the approved Smart Grid investments through the KPIs	CI	CI	R	

Source: Authors

TABLE 83: RESPONSIBLE FOR DETAILED STUDIES AND IMPLEMENTATION OF THE SMART GRID INITIATIVES

Smart Grid Initiative	Responsible for Detailed Study	Responsible for Implementation
Power quality monitoring and Metering Data Acquisition Systems	NLDC	NPT
Dynamic Thermal Circuit Rating	NPT	NPT
Wide Area Monitoring System	NLDC	NPT
Lightning Location System	NPT	NPT
Geographic Information Systems	NPT	NPT
Substation Automation System	NPT	NPT
High Voltage Direct Current technology	NPT	NPT
Static Var Compensator	NLDC	NPT
Fault Locator System	NPT	NPT
On-line Dissolved Gas-in-oil Analysis	NPT	NPT

Source: Authors

Complementing the implementation activities of the Refined Roadmap, those agencies tasked with the responsibility to perform detailed studies as well as the implementation of each Smart Grid initiative are also presented in Table 83.

Note that those Smart Grid initiatives connected with the control and monitoring of the Vietnamese Power System are assigned to the NLDC for studying and defining the main characteristics for their implementations. These activities should be implemented by NPT and be part of the approved CAPEX during the price control review performed by ERAV.

The recovery mechanism for the Smart Grid initiatives are part of the regulatory mechanism detailed in Circular No. 14/2010 / TT-BCT issued 15th of May 2010.

F.7 Conclusions and next steps

F.7.1.1 Refined Roadmap and the Key Performance indicators

The final refined roadmap has been presented and contains the initiatives and their prioritization in the short and medium term.

The metrics to monitor the Smart Grid initiatives from the technical, economic and regulatory point of view has been identified, analyzed and presented.

The KPIs were defined in terms of three different aspects and levels.

The roles and responsibilities of the involved stakeholders have been identified and defined.

Recommendations for the Roadmap implementation have been presented.

F.7.1.2 Regulatory Analysis

The main conclusions are summarized below.

The renewables integration policy is limited to wind and biomass projects and their connection to the nearest transmission grid point. According to the level of perceived incentives for investors, the transmission network will receive wind and biomass integration, which will have an impact on the reliability of the network as well as indirectly promoting the reinforcement of the network as well as its enhancement through the use of more advanced technologies like those included in the Smart Grid initiatives.

The linkage between the renewables policy and the Smart Grid applications presented in the current approved Vietnamese roadmap is not yet fully established. A policy covering both aspects is required in order to support the integration of renewables in the transmission network. The benefits from the integration of renewables are important and were quantified at system level in the Cost Benefit analysis performed earlier.

The Electricity Law has a general framework as does Decree No. 137/2013/ND-CP for introducing a general framework for international interconnections. Special conditions at odds with the ones that apply in general and that might disadvantage other participants in the electricity market should be avoided. In this context a clearer policy regarding international interconnections is required as this may affect the development and deployment of Smart Grid initiatives like HVDC as well as leading to an increased use of SVC in order to ensure the stability of the systems and link.

The mitigations of the KPIs stated in the Smart Grid Roadmap are considered insufficient when contrasted with the quality of service KPIs of other developed countries. For this reason, the following actions are recommended:

a. Introduce rigorous targets for quality KPIs in the medium and long term in order to reduce the number and duration of the interruptions.

b. Given the geography of Vietnam and its power system topology, introduce the SAIFI and SAIDI indicators by region (north, south, central), in order to better trace the quality and avoid masking some indicators for a particular region.

c. Introduce penalties for the transmission network operator if the regulatory targets for the quality indicators are not met.

The analysis performed in this study has also addressed many of these topics and is a baseline for improving the Smart Grids policy in Vietnam.

The main recommendations are summarized below:

a. The system security policy is an implicit part of the Grid Code and needs to be complemented with on-line security assessment criteria in order to avoid repeating past errors.

b. The Grid Code should also establish under the same policy, the tools that the System Operator must have in order to evaluate the security and perform on-line monitoring and control of the voltage/dynamic stability of the Vietnamese Power System.

c. The renewables policy is generally focused on wind and biomass sources, and the criteria, methodologies and incentives established are focused on the planning procedures rather than on fostering and assessing renewable energy developments. It is recommended that the renewables policy complement the developed Smart Grid roadmap in order to take advantage of those applications that ease the integration of renewable sources in to the transmission network.

d. The international interconnection policy needs a greater degree of clarity. This may have some significance for the development and deployment of some of the Smart Grid initiatives, e.g., HVDC interconnection, more stringent requirements for online monitoring and security assessment to ensure frequency/voltage problems do not cascade from one system to another, etc. A policy that addresses these points may enable the inclusion of technologies like HVDC and to increase the use of SVC for maintaining the stability of the systems and links

e. The Electricity Law does not define penalties or incentives for failing or exceeding the quality of service requirements. The revision of the Grid Code is also silent on the issue of penalties for failing to meet minimum standards in the quality of service. The lack of penalties weakens the introduction of Smart Grid technologies, which are being pushed by the industrial user community who have a poor perception of the quality of service of electricity supplies.

f. It is recommended that the Smart Grid policy complement Decision No.: 1670QĐ-TTg of November 2012 with both KPIs and penalties, in order to measure and track the performance of Smart Grid initiatives. As mentioned before, the final values of KPIs and penalties should be defined by ERAV based on the proposed values in this report mindful of the overall regulatory framework.

g. Finally, Circular No. 14/2010 / TT-BCT from 15th of May 2010 describes a detailed mechanism for the recovery of investments in the transmission system. The Circular clearly establishes that each year, based on the principle of ensuring full cost recovery and retaining permitted profits the operator is required to run the transmission grid according to the quality regulations and to meet key financial targets for the investment and development of the transmission grid. At present no improvements are recommended for the present mechanism.

Finally some recommendations for the Smart Grid implementation were presented; emphasizing the roles played by the different participants involved (ERAV, NPT, and NLDC). The matrix presented the activities to be performed until the implementation of the program. The responsibility assignment matrix known as a RACI matrix described the participation by various agencies in completing tasks or deliverables for the implementation of the Smart Grid program.

Complementing the implementation activities of the Refined Roadmap, those tasked with the responsibility to perform detailed studies and implementation of each Smart Grid initiative were also identified.

There is a basic legal framework underpinned by the Electricity Law, that supports the development of the proposed Smart Grid initiatives in the transmission system. It was recommended that a formal Decision with a Refined Roadmap be issued. This approach will reduce the risks associated with the introduction of a new technology and will do much to smooth the way through the multi-layered approvals process.

A proposed Amendment to the current Smart Grid Decision is presented in 'ANNEX -1 Proposed Amendment to the Decision No.: 1670QĐ-TTg', which is based on the jurisprudential method for introducing new technologies.

The regulatory recovery mechanism of the Smart Grid initiatives detailed in Circular No. 14/2010 / TT-BCT issued 15th of May 2010 is also confirmed as the prevailing procedure until the regulatory approach for governing the transmission network changes.

Finally, it was recommended that a separate Decision be issued for the approval of the KPIs to control and monitor the Smart Grid initiatives so that ERAV have the flexibility to change these values (if required) without having to re-issue a Decision of the Roadmap for each change.

F.7.1.3 Next Steps

In general, the next steps in the Smart Grid Development in Vietnam are divided in two separate levels:

a. Approval level; and

b. Implementation level.

At the approval level the following steps are recommended according to the RACI matrix previously presented:

a. NPT internally approves the Refined Roadmap;

b. NPT presents the Final Report to other stakeholder agencies;

c. The involved stakeholders define the priorities for the implementation in the short-term;

d. NPT presents a request for approval of the Smart Grid initiatives to ERAV;

e. ERAV approves the Smart Grid initiatives in the short, medium and long term by issuing a Decision;

f. ERAV defines the final KPI targets for the Smart Grid implementation based on the recommended values;

g. ERAV issue a separate Decision in order to approve the KPIs; and

h. The Institute of Energy should include the approved Smart Grid applications in the Master Plan.

Finally, at the implementation level the following steps are recommended:

a. Conduct trainings sessions on Smart Grid theory for the involved stakeholders;

b. Perform site visits in order to provide practical experience of the implementation of working Smart Grid solutions;

c. Perform a complete survey of the historical data, information and requirements needed for each Smart Grid initiative in order to conduct detailed studies; and

d. Collect the surveyed data in one repository for different users in order to have single point of reference for future Smart Grid developments.

e. Conduct detailed studies of those Smart Grid applications identified as a priority.

ANNEX 1. Proposed Amendment to the Decision No.: 1670QĐ-TTg

Following is a proposed Amendment to the current Decision in order to introduce the new initiatives identifies in the study.

The underlined text corresponds to the new one.

Article 1. Approve project of Smart grid development in Vietnam is as following contents:

1. Targets:

a) General target: Develop Smart grid with support of high technology in order to improve quality and reliability of power supply; contribute demand side management, encourage to implement energy saving and efficiency; create favorable conditions for improvement of labor productivity, reduction of investment demand on generation and power network; enhance the rational exploitation of energy resources, ensure national energy security, contribute to environmental protection and sustainable socio-economic development.

b) Preliminary and urgent initiatives:

These activities should be finalized in 2017 in order to have a solid base for the Smart Grid development:

- Implement local automation strategy in substations with three autotransformers.
- Present a plan to evaluate unsuccessful single pole re-closing in substations and address the verification of the design of neutral reactance in substations where a high percentage of errors occur.
- Present a plan for short circuit current evaluation to highlight the critical areas both at present and in the future.
- Develop a project for breaker substitutions in order to solve the problem of short circuit current exceeding the breakers rated current in critical areas.
- Present a plan for the installation of reactors between bus bars in those areas known to have high short circuit currents.
- Present a plan to include and operate automatic State Estimation algorithms and on-line N-1 Security Assessment procedures on a daily basis.
- Develop a project for on-line Dynamic Security simulation and integrate it in the daily operational procedures.
- Present a plan to implement secondary Load-Frequency Regulation (Automatic Generation Control).
- Present a plan to perform a detailed survey of all installed protection systems.
- Present a plan to double the protections on most critical lines.
- Develop an installation strategy of protection that will support a consistent and incremental improvement of system reliability.
- Present a plan to either repair or replace unsuitable or damaged protection systems.

c) Specific target:

- Finalize legal framework of power sector to create legal basic to develop Smart grid: Review, adjust, supplement current legal documents; develop new legal documents on development of renewable energy; develop technical standards, rules accordingly.
- Develop IT infrastructure system, communication system and improve monitoring system, automation and control system for power system, remote metering system:
  + To 2015: Establish adequate baselines (technical, economic and regulatory) to address the commencement of the deployment of Wide Area Measurement System, Lightning Location System, Power quality monitoring system, Metering Data Acquisition System, Geographic Information Systems and Dynamic Thermal Circuit Rating. In the meanwhile continue with Substation Automation System implementation at the already planned installation pace.

+ To 2016: Exploit all functions of Energy Management System (EMS) of SCADA/EMS system at National Load Dispatch Center and regional load dispatch centers. Begin the feasibility study for future Static Var Compensator. Address the benefits evaluation of Fault Locator System initiative.

+ To 2017: Begin the feasibility study for future High Voltage Direct Current lines, both for the interconnection with neighbouring countries and for long links connecting the Northern and Southern parts of Vietnam.

+ To 2022: SCADA/DMS system of Power Corporations; remote metering system will be invested adequately to whole larger customers.

- Improve reliability of power supply: System average interruption frequency index – SAIFI will be reduced 10% and System average interruption duration index – SAIDI will be reduced 20% after each 5 years period.

- Equip automatic and controllable equipments in order to enhance labor productivity in power sector: 110kV transformers are equipped automatic and remote controllable equipments in order to reduce staff to 3-5 persons in each substation; implement the remote switching in medium voltage network.

- Enhance ability to forecast demand and develop of power supply plan; limit outage or power cut caused by lack of generation through mechanism of loading shift in the peak hours or emergency condition: Decrease 1-2% of peak load through the application of Advanced Metering Infrastructure (AMI).

- Implement the technical solutions, management measures in order to reduce power losses (technical and non-technical losses) in power system (transmission and distribution) from 9.23% in 2011 to 8% in 2015.

- Apply Smart Grid technology to stably connect, operate new and renewable energy; facilitate efficient exploitation of new and renewable energy sources, encouraging development and increasing density of new and renewable energy in generation; contribute to environmental protection, national energy security.

- Encourage research and manufacturing a number of electronic products on smart grid in Vietnam in order to meet the demand for Smart Grid technology.

- Facilitate customers can directly know and manage specific information on tariff and electricity use.

2. Smart Grid development roadmap in Vietnam

Approve Smart Grid development roadmap in Vietnam that was divided into three phases as follow:

a) Phase 1 (2016-2020):

- Program of enhancement of efficiency of power system operation:

  + Complete the SCADA/EMS project for National Load Dispatch Centre, Regional Load Dispatch Centers. Install completely the devices to collect operation data from substations/power plants connected to 110kV grid and above; complete automatic reading system of electronic meter at power plants, and delivery points between power plants and transformer station at 500, 220, 110kV.

  + Implement the applications to enhance reliability and to optimize operation of transmission, distribution grids; reduce losses; especially the applications to protect safety of 500kV operation such as fault recorder system, detection and protection system of outage wide-area. Such Smart Grid solutions include: Substation Automation System, Wide Area Measurement System, Lightning Location System, Power quality monitoring system, Metering Data Acquisition System, Geographic Information Systems and Dynamic Thermal Circuit Rating. After the preliminary activities, necessary for the feasibility study and benefits evaluation, the deployment of Static Var Compensators and a Fault Locator System has to be performed. Finally address the feasibility study for future High Voltage Direct Current lines.

  + Check and monitor the implementation of regulation on mandatory data collection system in power plants, substations connected to 110kV networks and above.

+ Initially equip SCADA/DMS system for distribution power corporations, provincial power companies. This includes the software, hardware and Communications system, automation and telecontrol system of selected 110kV.

+ Training and enhancing the Smart Grid implementation capacity of National Power Transmission Corporation, National Load Dispatch Centre, distribution power corporations, power companies.

+ Complete full integration of Smart Grid applications in daily system operation and asset management procedures.

+ Complete the programs, technical assistance project on load research, demand side response for distribution power corporations, power companies.

+ Development and implementation of advanced operation tools for the integration of large amount of non-manageable renewable power in the system (wind, solar energy…).

+ Building of High Voltage Direct Current lines according to the results obtained from the feasibility study performed in Phase 1.

- Pilot programs:

  + Pilot project for advanced metering infrastructure (AMI) applied to selected big customer in Ho Chi Minh City Power Corporation in order to implement Demand Side Management program.

  + Pilot project for integration of renewable generation in Centre Power Corporation: apply for small hydro power plants, new and renewable generation.

- Building of related regulatory framework:

  + Complete the load research procedures

  + Develop the mechanism to encourage customer participating in demand side management program in pilot program in HCMC PC. Accessing the program result and completing the encouraging mechanism

  + Building the legal framework for applying the technical standards, the dispatching regulation for substation automation and telecontrol in power system.

  + Recommend the financial mechanism to develop Smart Grid.

  + Base on researching result and accessing of efficiency of programs in actual, issue or review regulatory documents in order to deploy infrastructure and implement Smart grid applications.

- Development of technical regulations: Researching, issuing of technical standards for Smart Grid, such as: advanced metering infrastructure, technical requirements for automation system, telecontrol system of transformer stations; SCADA/EMS/DMS system; integrated renewable generation and embedded generation standards; configuration of Smart grid and related regulations.

- Communication program for social:

  + Preparation and Full dissemination of Communication program for the Smart Grids for: Institutions, Generation Companies, Power Corporations, Large Customers

  + Preliminary dissemination of the program for residential customers.

b) Phase 2 (2021-2025):

- Keep doing the Program of enhancement of efficiency of power system operation, focus on distribution network; equip IT and communication infrastructure system in distribution network:

  + Complete SCADA/DMS system for the distribution power corporations; continue to equip the automation equipment for 110kV substations.

  + Implement SCADA/DMS for some provincial power companies that have big demand, connect to some selected MV substations.

  + Continue to build the Smart Grid implementation capacities for the distribution power corporations and power companies.

  + Develop test and pilot program on optimal transmission network operation

- Implement Smart grid applications:

  + Dissemination of AMI lesson learnt. Extension of AMI system to big customers in all PCs. Implement pilot project allowing customer to trade in on the competitive market (wholesale competitive market and pilot retail competitive market) at all PCs.

+ Integrate embedded generations, new energy generations, and renewable generations into the network at medium and low voltage.

+ Development of pilot projects for Smart Homes.

+ Creation and implementation of a pilot Smart City

- Building of related regulatory framework:

  + Research and recommend the authority to issue the mechanisms: encouraging smart grid applications in development of renewable energy sources; encouraging smart grid applications in zero energy house (non-consumed of energy from outside); encouraging smart grid applications in energy trading between customers and power utilities.

  + Develop encouraged mechanism for residential customer to participate the DSM program.

- Develop technical regulations: research and recommend the authority to issue technical regulations/standards for energy storage technology, smart appliances used in-house which can control energy consumption follow supply condition or tariff changing.

- Communication program for social:

  + Update of Communication program for the Smart Grids to include the new fee and tariffs approach.

  + Full dissemination –in stages- of the program for residential customers.

c) Phase 3 (<u>2026-2030</u>):

- Continue to implement equip IT and communication infrastructure system in distribution network:

  + Deploy the SCADA/DMS system for all provincial/district power companies to reasonable number of medium-voltage distribution stations.

  + Extend the advanced energy management and optimal tools in operation from transmission grid to distribution network.

  + Implement AMI system to residential customer; provide customer the opportunities to trade in on the retail competitive market.

  <u>+ Possible investment in "On-line Dissolved Gas-in-oil Analysis" for the prevention of transformers faults, especially on the most valuable equipment.</u>

  + Continue to encourage development of embedded generation.

- Program of Smart grid applications implementation: Implement the smart grid applications that allow electricity demand-supply balancing at customer level (Smart Homes). Disseminate the use of renewable energy widely in distribution grid with the time-of-usage electricity price mechanism associated with retail competitive power market operation.

- Build regulatory framework which allows deploying smart grid applications based on existing information technology infrastructure.

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MAPS, FIGURES AND TABLES SOURCES

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ENDNOTES

1. It is important to maintain a holistic view of the power system and to avoid partial analysis that only looks at the transmission activity.

2. The Technical Analysis was performed in Task-1 Report.

3. The Cost Benefit Analysis was performed in Task-2 Report.

4. The Rate of Return on equity for the National Power Transmission Corporation (%) is determined to ensure that fiscal targets for investment and development of the transmission grid.

5. Article 22 of the Grid Code.

6. Article 23 of the Grid Code.

7. Please refer to Task-2 Report.

8. Please refer to Task-2 Report.

9. The only document available and received regarding the regulatory framework is the Electricity Law of 2004 and the Grid Code for Generation Competitive Market Draft 4.1.

10. According to the Article 66, pint 1, paragraph h) of the Electricity Law.

11. The only document available and received regarding the regulatory framework is the Electricity Law of 2004 and the Grid Code for Generation Competitive Market Draft 4.1.

This document presents a study on smart grid technology options for Vietnam. With electricity consumption nearly matching generation in recent years and insufficient investment in new power plants, the electricity grid is under constant strain by the growing economy. Realizing the large technical, institutional and financial challenges posed by this expansion level will be a key priority for Vietnam's grid system operators in the short term. Building on international experiences the report identifies viable smart grid solutions for Vietnam's transmission network.

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