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Ministry of Industry and Trade

Proposal of an Appropriate Support Mechanism for Wind Power in Viet Nam

Technical Assistance to the General Directorate of Energy,

Ministry of Industry and Trade

(Short Version)

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Citation: Cuong, N.D. and Dersch, D. (2014): **Proposal of an appropriate support mechanism for wind power in Vietnam (Short Version)**, Project study

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Comments on the short version report

This report is a short version of the full report that has been submitted to the General Directorate of Energy by GIZ and its study team. The full report covers all aspects of the study in more detail and provides additional information on the methodical approach, the situation of the power sector and wind power in Vietnam as well as on international trends in wind energy. In particular, the full report outlines the FIT calculations and funding estimates for on-, near- and offshore wind, whereas the short version focuses on onshore wind power.

Executive Summary and Key Recommendations

Context

Vietnam's *Power Development Plan VII* sets out targets for the installation of wind power of **1 GW by 2020 (Target 1) and 6.2 GW by 2030 (Target 2)** (Decision No. 1208/QD-TT), corresponding to a share of wind-generated electricity in the projected national generation of **0.7% in 2020, and 2.4% in 2030**. To promote the wind power development in Vietnam, Decision 7/2011/QD-TTg has been issued by the Prime Minister on June 29, 2011. Article 14 specifies a Feed-In-Tariff (FIT) of 7.8 US Cents/kWh for the remuneration of grid-connected wind power projects. This FIT consists of an "electric buying price" of 6.8 US Cents/kWh paid by EVN and a "state support electric price" of 1.0 US Cents/kWh to be paid to the project developers by the Vietnam Environment Protection Fund (VEPF). However, more than two years after issuance of the decision, there have been no new wind projects applying for permits and to date only approximately 50 MW of wind power capacity have been installed.

To address this challenge, the Ministry of Industry and Trade (MoIT) requested the study team to undertake the following tasks: i) Re-calculate the FIT to be paid for wind energy, ii) possibly re-design the support mechanism in order to improve the framework conditions for wind energy development in Vietnam and to attract project developers.

The objective of this study has been to: i) support MoIT in reviewing the existing FIT support scheme for wind energy, ii) determine the causes for the slow development of wind power deployment and iii) identify adequate solutions to overcome possible barriers, including the re-calculation of the existing FIT.

Suggested adjustment of FIT level

According to the analysis, **FIT levels of 10.4 US Cents/kWh (onshore) and 11.2 US Cents/kWh (nearshore) would trigger the full-fledged development of the Vietnamese wind market,** as such rates would allow for an internal rate of return (IRR) of 10% on typical Target 1 wind projects (FIT guaranteed over 20 years). Assuming a realistic range of scenarios for key input variables of the applied financial model (discounted cash flow), the sensitivity analysis results in a FIT range of 9-12.5 US Cents/kWh for onshore and 10-13 US Cents/kWh for nearshore wind. The results for on- and nearshore wind are largely based on data derived from feasibility and pre-feasibility studies provided to the study team by wind farm developers, as well as information compiled from questionnaires, interviews and public resources (such as the GIZ and World Bank wind speed measurements).

For **offshore wind**, no data was available for the Vietnamese market. Thus, only rough estimations could be undertaken based on data from European projects, which was adapted to the market conditions in Vietnam. The FIT necessary to attract investors would have to amount to 23 US Cents/kWh in the base case scenario.

In general, data quality – particularly of wind conditions and capacity factors – remains a source of significant uncertainty, which can have substantial effects on the FIT levels needed for financial closure at the threshold IRR. This uncertainty has been addressed as much as possible by means of sensitivity analyses. Still, future FIT re-calculations should be based on higher quality wind data, so as to reduce error margins. For this purpose, long-term wind measurements under standardized conditions, such as the ones currently undertaken by GIZ and the World Bank, are essential.

Suggested adjustments to wind power investment climate

While an adequate FIT level is a determining factor, the current investment conditions on the Vietnamese wind power market constitute other significant barriers to the attraction of new market players, as security of investment is too low.

Compared to traditional power plants and due to the very specific cash flow profile of wind power projects (with frontloaded investments and long payback periods of 10 years and more), investment decisions in the wind energy sector depend greatly on the risk profiles of transactions, which in turn depend on local market rules and deal structure.

The following aspects were identified as risk factors and have to be tackled in order to **provide adequate and secure conditions for investments on the Vietnamese wind power market**:

(i) Redesign of the FIT payment as a bankable "one-stop-shop solution" with a single source of payment – as opposed to the current scheme, where payments are made by two entities (EVN and VEPF);
(ii) Government guarantee for FIT payment;
(iii) Better quality wind speed measurements and improved standardization;
(iv) Comprehensive information on wind power planning at provincial and national level
(v) Current uncertainties regarding overlapping land use planning;
(vi) Present limits in local consulting capacity and logistics;
(vii) Duration and transparency of licensing procedures;
(viii) Enforcement of standard agreements for network connection and power purchase;
(ix) Tax-break opportunities to developers and manufacturers etc.

Different investor types are affected in different ways by the above mentioned barriers. While highly subsidized investors are more immune to market uncertainties, specific risks can keep certain types of prudent investors completely out of the market – even at much higher FIT levels than the one recommended above. At the same time, intelligent adjustments to the wind power specific investment climate are often just as conducive for an increase of deal closures as a higher FIT level. For instance, benefits of a reduced corporate tax for wind park projects are estimated to contribute an additional 0.3 US Cents/kWh to the FIT. The benefits of an import tax exemption are even larger: a 10% import tax exemption on component costs corresponds to a FIT surplus in the range of 0.7 to 1.0 US Cents/kWh.[1] In addition, a lease payment exemption for wind power projects accounts for a corresponding FIT surplus of about 0.5 US Cents/kWh if typical lease levels are taken as a reference.

The main aspects that concern investors are the quality of investment proposals as well as the pre-defined requirements to meet minimum technical (wind audits, technical design and specifications), economical (financial modelling and risk assessment) and contractual (legal binding and enforceable agreements and guarantees) **standards for bankability.**

Availability and conditions of debt funding

The availability of debt funding and the conditions, under which debt is available, is a central financial obstacle for wind power development in Vietnam. Thus, as part of this study, an in-depth analysis has been dedicated to this aspect. For the above mentioned FIT levels of 10.4 US Cents/kWh (at a pre-tax project IRR of 10%) bankability can likely be achieved for average debt funding interest rates of 6%. Loans at 10% interest rate may still result in bankable projects. However, adverse cost and wind scenarios could result in financial stress and need to be thoroughly analyzed within the projects' feasibility studies. Furthermore, **loan maturity** has an

[1] Other factors such as process and licensing improvements, sovereign guarantees for debt financing or regulatory and legal risks could – in principle – be equally quantified in terms of FIT adjustment but are beyond the scope of this study.

important impact on project bankability. Moving to longer maturities increases the project attractiveness to debt investors (higher minimum debt service coverage ratio, DSCR) as well as to equity investors (higher equity IRR).

Developing the national wind power market by targeting diverse investor types

In order to meet the initial **Target 1** of 1 GW wind power installed capacity by 2020, the **total investment on capital expenditures** (CapEx) over a six year period has been estimated at approximately **USD 2 billion**[2]. The corresponding equity share would be approximately USD 600 million. Accordingly, the total debt requirement is estimated at USD 1.4 billion (debt level 70%).

More than one investor type must be targeted in order to assure i) a higher probability of solid demand for wind power licensing towards Target 1 and ii) a healthy market growth with Target 2 in mind. To allow for such a government-guided market development, simulations were carried out for **three typical investor types** within the study, which are assumed to be representative for a large share of the overall wind investors' profiles desirable for Vietnam[3]. In this study, the three groups are characterized mainly by (a) their specific expectation on the **IRR** of the wind power project (in light of the same set of market conditions and their specific risk tolerance) and (b) their ability to raise **debt funding** at specific conditions.

(i) **"Highly subsidized investors":** Project Sponsors include international donors which team up with public entities, and are driven by renewable energy development objectives beyond IRR. They are predestined to initiate wind power development in an emerging market due to their unique ability to bear early market risks ("lenders of last resort") and/or access debt funding at interest rate levels in the range of 1-2%, allowing for financial closure at low, single digit project IRRs. Securing a debt volume of about 500 million USD via this "early mover" group could provide a third of the required installed capacity to reach Target 1 by 2020[4].

(ii) **"Strategic investors":** Simultaneously, another third of planned capacity could be provided by strategic investors with access to balance sheet financing, internal cross-subsidized financing or foreign pools of debt financing in the range of 6% interest rate. These 'strategically-oriented' investors could consist of turbine manufactures, large industry enterprises, and sovereign wealth and pension funds. They could be targeted and incentivized by means of road shows and investment proposals.

(iii) **"Fully commercial investors":** The remaining investment volume may be provided (probably with a certain time lag, except for extremely attractive wind sites) by commercial investors that rely on local commercial loans at an interest rate of 10%. Strengthening the local banking sector in order to increase local commercial debt funding as well as providing additional incentives, like the above mentioned tax breaks, could help towards developing the market for local commercial investors.

[2] For this estimate, a share of 100% for onshore wind is assumed. Calculations for nearshore wind FIT are provided in the full version of this report.
[3] Non-rational investors and tax arbitrage and avoidance schemes or investors "betting" on renegotiation were not taken into account.
[4] Assuming a 70/30 debt-equity ratio of project funding.

FIT funding

A Target 1 installation of 1 GW wind power in 2020 and 6.2 GW in 2030 (corresponding to a share of 0.7% or 2.4% of the total projected electricity generation) could be achieved through an 80/20 ratio of onshore and nearshore wind power. With the calculated FITs of 10.4 US Cents/kWh (onshore) and 11.2 US Cents/kWh (nearshore), this would result in an **additional average annual funding requirement of USD 68.6 million**[5], when taking the projected levels of average electricity production costs for the whole system as a reference[6] (see Chapter 0).

Various FIT funding sources that originate either from a levy on the electricity price or from tax funding are discussed in more detail in the full version of this study. Given the recent development of electricity prices for retail and industry customers in Vietnam, electricity price increases for end customers are, of course, sensitive measures. However, in the period of 2015 to 2030, the above-mentioned **FIT adjustment would increase the electricity price per kWh on average by only VND 3.5** and by a maximum of VND 5.3/kWh in 2023.

International experience suggests that these funding requirements and levy increases are likely to be below a level that is noticeable to end-consumers and will therefore not influence electricity consumption patterns.

Outlook

The analysis performed in the study shows that a support mechanism, including FITs of 10.4 US Cents/kWh for onshore, and 11.2 US Cents/kWh for nearshore, would be expected to contribute substantially to wind energy market development in Vietnam. However, a FIT alone will not guarantee that wind power deployment will develop according to plan. In addition to the proposed FIT, **regulation and administrative procedures need to be streamlined** in order to develop wind power at the lowest possible cost.

Further details of the procedural enhancements, including an appropriate communication strategy should be considered. At the same time, a **monitoring process** should be set up that ensures an effective adaptation to market developments and that is also transparent towards the market, and all its stakeholders (developers, investors, etc.). This monitoring system will allow for the implementation of the support mechanism in a way that **government can control the speed and cost implications** of wind power deployment. GIZ stands ready to support these efforts.

Apart from this perspective of market development and related costs, a number of technical aspects have to be considered. These range from the prevention of hotspots to planning methods for the integration of variable renewable energy technologies into the existing electricity system.

In the short term, the study team recommends that the Vietnamese Government introduces a **transparent rule to avoid "hot spots"** already during the initial 1 GW Wind Target Phase. That is, the total capacity of wind projects feeding into the same transmission line should never exceed technically and economically reasonable levels, as recommended in [IEA 2014]. This can be achieved by setting a simple capacity "safety cap" for each 110 kVA substation and applying a first-come first-served rule.

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[5] The average describes the arithmetic mean of funding costs in the 16 year period. The lowest funding requirement is USD 5.0 million in 2015; the highest is USD 112.7 million in 2027.

[6] Two scenarios have been developed. The first scenario assumes constant FITs of 10.4 US Cents/kWh for onshore, and 11.2 US Cents/kWh for nearshore from 2015-2030. A second scenario is based on the assumption that considerable learning and scale effects will possibly allow for a reduction of 1.0 US Cent/kWh of both FITs as of 2021, once a certain maturity of the wind power market has been reached. For the first scenario, the additional average annual funding requirement from 2015 to 2030 is USD 68.6 million, translating into an average levy on the electricity price of VND 3.5/kWh . For the second scenario, the annual funding requirements and the levy rate would be even lower. Further detail on both scenarios is provided in Chapter 0.

With regard to **planning methods**, cutting-edge tools as well as lessons from past experience allow for improved pathways and macroeconomic net benefits, by optimizing the costs and benefits of different renewable energies (wind, PV, hydro, and biomass) and thus their **value to the power system**. Each RE technology can be analyzed with regard to its interaction with the overall national generation mix and transmission system, so as to allow for an optimal expansion of RE technologies in time and space, beyond Target 1 (i.e. 1 GW of wind power capacity by 2020).

In the future, the concept of direct sales might be an additional potential business model to advance the use of wind energy in Vietnam. The long version of the study provides more insights on this topic.

Table of Contents

Abbreviations

AIS	Automatic Identification System
BNEF	Bloomberg New Energy Finance
BOT	Build Operate Transfer
CapEx	Capital Expenditure
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CEER	Council for European Energy Regulators
CO_2	Carbon Dioxide
DPC	District People's Committee
DNO	Distribution Network Operator
DoC	Department of Construction
DoIT	Department of Industry and Trade
DoNRE	Department of New and Renewable Energy
DSCR	Debt Service Cover Ratio
EEG	Erneuerbare Energien Gesetz; German Law on Renewable Energy
EIB	European Investment Bank
EU	European Union
EVN	Electricity of Vietnam
EWEA	European Wind Energy Association
EUR	Euro
FIT	Feed-In-Tariff
FS	Feasibility Study
FX	Foreign Exchange Rate
GDE	General Directorate of Energy
GDP	Gross Domestic Product
GHG	Green House Gas
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH
GWEC	Global Wind Energy Council
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IPP	Independent Power Producer
KfW	Kreditanstalt für Wiederaufbau
LCOE	Levelized Costs of Electricity (equivalent LEC)
LEC	Levelized Electricity Cost (equivalent to LCOE)
LNG	Liquefied Natural Gas
MoF	Ministry of Finance
MoIT	Ministry of Industry and Trade, Vietnam
MoNRE	Ministry of Natural Resources and Environment
MPI	Ministry of Planning and Investment
NREL	American National Renewable Energy Laboratory
OECD	Organization for Economic Co-operation and Development
ODA	Official Development Assistance
OpEx	Operational Expenditure
OWP	Offshore Wind Park
PDP	Power Development Plan

PECC3	Power Engineering Consulting Company 3
PECC4	Power Engineering Consulting Company 4
PPA	Power Purchase Agreement
PPC	Provincial People's Committee
PV	Photovoltaic
PVN	Petro Vietnam
Q	Questionnaire
RE	Renewable Energy
RE IPPP	South African RE Independent Producer Procurement Program
RES	Renewable Energy Source
RET	Renewable Energy Technology
REVN	Vietnam Renewable Energy Joint Stock Company
SPV	Special Purpose Vehicle
TOE	Tons of Oil Equivalent
TSO	Transmission System Operator
UoS	Use of System
USAID	United States Agency for International Development
USD	US Dollar
VDB	Vietnam Development Bank
VEPF	Vietnam Environment Protection Fund
VND	Vietnamese Dong
vRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital
WB	World Bank

Units:

GW	Giga Watt
GWh	Giga Watt hour
km	Kilometer
kV	Kilo Volt
kW	Kilo Watt
kWh	Kilo Watt hour
m	Meter
s	Second
MVA	Mega Volt Ampere
MW	Mega Watt
MWh	Mega Watt hour
TOE	Tons of oil Equivalent

All FIT calculations based on a FX rate of: USD1 = VND 21,090; EUR 1 = 29,032 (Source Vietcom Bank, July 2014)

List of Tables

List of Figures

1 Introduction

Renewable Energy (RE) plays an increasing role in Vietnam's future energy supply. The National Master Plan for Power Development 2011 – 2030 (PDP VII) targets a share of total electricity generation from Renewable Energy Sources (RES) of 4.5% in 2020 and 6% in 2030.

Wind energy is seen as one of the most promising RES in Vietnam. Stretched over a 3,000 km of coast line and located in the monsoon climate zone, the country provides good potentials for the deployment of wind power technologies. Aware of this potential, the government plans to increase the total wind power capacity to 1,000 MW by 2020 and 6,200 MW by 2030 (PDP VII), equivalent to 0.7% and 2.4% of the total forecast electricity production.

To date, the installed capacity of wind power is 52 MW. Even though a support mechanism for wind power was introduced in 2011, i.e. a Feed-in-Tariff (FIT) of 7.8 US Cents/kWh, the development of the sector has not reached the desired pace. This FIT consists of an "electric buying price" of 6.8 US Cents/kWh paid by EVN and a "state support electric price" of 1.0 US Cents/kWh to be paid to the project developers by VEPF.

Considering the current situation, it is questionable whether the current framework provides the adequate conditions to reach the targets set out by the PDP VII. The Ministry of Industry and Trade (MoIT) therefore seeks to review the current support mechanism and to identify suitable measures for increased development of wind power in Vietnam.

1.1 Objective

This study aims to provide MoIT with a comprehensive analysis of the current situation of the wind power sector in Vietnam and will outline recommendations, which are based on the review and analysis of the existing support scheme and its impacts on the sector development. This way, the targets set out by the PDP VII can be achieved in a sustainable way.

The results of this study will provide all necessary information to policy makers and government planners in order to deepen their insight on issues and challenges regarding wind energy expansion in Vietnam. A basis for the revision and approval of a new incentivizing mechanism is created through the re-calculation of the FIT. The main goal is to establish improved framework conditions for wind energy in Vietnam, which could stimulate investments and boost further development.

1.2 Scope

This study consists of two main parts. The first part (Chapter 1-4) outlines the status quo of wind energy in Vietnam and other countries where wind energy plays an important role in the respective national energy supply. The second part (Chapters 5 and 6) discusses paths and strategies as well as financing options that may be integrated into a revised support mechanism for wind energy in Vietnam. Chapter 2 examines the power sector in Vietnam, focusing in particular on the wind power sector. Within Chapter 3, an overview of the development of the global wind energy market, international cost trends and experiences with different support schemes as well as existing barriers for wind energy deployment is given.

Chapter 4 provides a qualitative and quantitative analysis of the current support mechanism and framework for wind energy in Vietnam. It summarizes the procedures that project developers have to follow in order to develop wind power projects, analyses the strengths and barriers of the current processes, and discusses the adequacy of the current FIT. Chapter 5 contains the proposal for the re-design of the support mechanism for wind energy in Vietnam. This comprises the exploration of potential impacts of FIT adjustments on the financial viability of wind power projects as well as adaptions to be made to the legal frameworks. Chapter 6 discusses the financing options for support mechanisms. This includes the rationale for government support and a comparison of tariff-funded versus tax-funded options.

Finally, the study formulates key recommendations based on the findings from the analysis and draws respective conclusions. Chapter 7 provides an outlook and the proposed next steps.

Please note that the report at hand is a short version of the full report which has been submitted to the General Directorate of Energy (GDE) by the study team. The full report covers all aspects of the study in more detail and provides additional information on the methodical approach, the situation of the power sector and wind power in Vietnam as well as on international trends in wind energy. In particular, the full report outlines the FIT calculations and funding estimates for on-, near- and offshore wind, whereas the short version focuses on onshore wind power only.

2 Situation of power sector and wind power in Vietnam

According to the National Power Development Master Plan VII, the electricity demand of Vietnam will continue to grow by 14.1% p.a. during the period 2011-2015 and then decrease to a growth of 9.9% p.a. during the period 2016-2020. Thereafter, growth rates are expected to amount to 8.1% p.a. from 2021 to 2025 and 7.2% p.a. from 2026 to 2030.

In order to meet such rapidly growing demand, the Government of Vietnam intends to include the exploitation of renewable energy sources into the national energy mix. The targets for the share of electricity generated from renewable resources are 4.5% in 2020 and 6% in 2030 (Decision No. 1208/QD-TT).

With more than 3,000 km long coastal line and its location in the monsoon climate zone, Vietnam is believed to have a good potential for wind energy (TrueWind Solutions, 2001). To promote clean power generation and exploit effectively available renewable energy sources, the Government of Vietnam has formulated and set up the roadmap for wind development in Vietnam for the period up to 2020, with outlook to 2030. The target of wind development during that period is 1000 MW in 2020 (accounting for 0.7% of total electricity generation) and 6,200 MW installed capacity in 2030 (accounting for 2.4% of total electricity generation) (Decision No. 1208/QD-TT).

In order to promote the development of wind power in Vietnam, Decision No, 37/2011/QD-TTg was issued by the Prime Minister on 29 June 2011, which provides a support mechanism for wind power and regulates the Feed-In-Tariff (FIT) to be paid to producers of grid connected wind power projects. According to this regulation, the buyer is obliged to purchase the electricity from wind power projects at a delivery price of 7.8 US Cents/kWh (Article 14 of Decision No, 37/2011/QD-TTg).

However, after more than three years after the issuance of the decision, wind power development in the country has not lived up to early expectations. Up to now, there are only three wind farms with a total installed capacity of 52 MW in operation. Currently, all three projects are not applying the tariff stipulated in Decision No. 37 as it is considered too low for a profitable operation of wind farms.

Against this background, a re-calculation of the wind power FIT is necessary if the Government still wants to develop wind power according to the targets set out in Decision No. 1208/QD-TTg.

2.1 Power sector development

2.1.1 Power production

The energy sector of Vietnam is characterized by three main energy sub-sectors: i) electricity; ii) coal, and iii) oil & gas[7]. These three energy sub-sectors have seen strong growth over the past decade in all stages of the value chain: from exploitation, conversion and transformation, transmission, distribution to export-import and energy consumption.

Exploitation of primary energy sources has seen the most extraordinary growth. Statistical data show that in 2012, coal production increased 3.6 times compared to 2000, reaching 42.5 million tons, enough to ensure domestic demand as well as exports. Vietnam coal reserves amount to approximately 6.1 billion tons, mainly located in Quang Ninh, the Northeast of Vietnam (69%), and

[7] Currently, there are three separate development master plans in Vietnam: power development master plan (PDP VII); coal development master plan (for all energy flow, including electricity generation); and oil & gas development master plan (for all energy flow, including electricity generation).

in Hung Yen and Thai Binh (about 27%). The lifetime for coal reserves is six years based on consumption and just three years based on production estimates.

For crude oil, the output reached around 15-16 million tons per year for the period of 2002 to 2012. Exploitation of natural gas was 9.4 billion cubic meters in 2012. Oil and gas potential has been verified at about 1.05 - 1.14 billion tons of oil equivalent (TOE), with the gas share accounting for more than 60%.

A total of 130.99 billion kWh of electricity has been produced in 2013, of which hydropower accounted for the largest proportion (39.66%), followed by gas (32.71%) and coal (20.50%). The remaining production came from renewable sources, fuel oil and diesel.

Vietnam has a high potential for renewable energy, including wind, solar, biomass, biogas and geothermal energy. A number of support incentives have been issued and are being developed to promote the development of renewable energy resources, including existing tariff mechanisms for wind and biomass in the form of a FIT and small hydro power in the form of an avoided cost tariff. The figures below illustrate the energy mix according to owner of the power plants and according to generation type respectively.

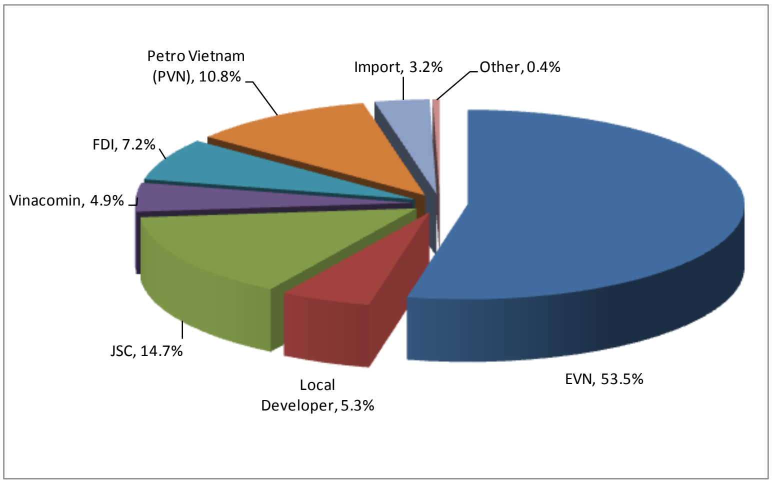

Figure 1: Generation mix by owner in 2013 (EVN, 2014)

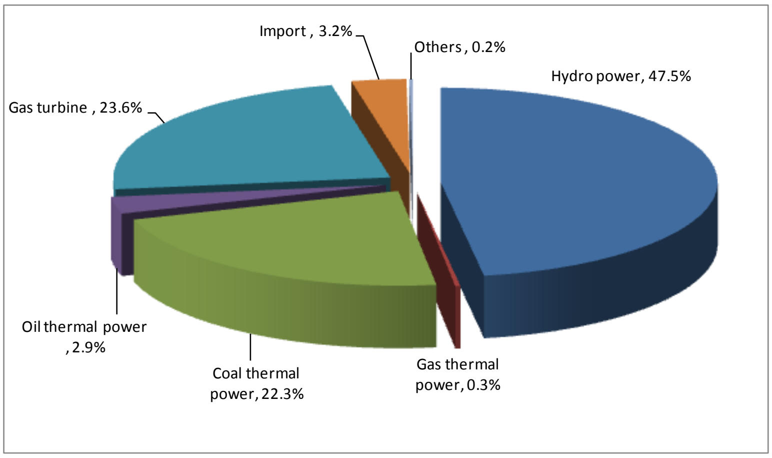

Figure 2: Generation mix by generation type in 2013 (EVN, 2014)

In 2013, a total of 29,498 MW generating capacity was installed, of which hydro power accounted for 47.5%, gas turbines for 23.6%, coal for 22.3% and the remainder was constituted by oil and renewable energies. The number of power plants that are larger than 30 MW is 97, of which 63 are hydro power plants with an average capacity of about 250 MW, followed by coal plants (15 plants) of about 400 MW average capacity, and gas with 12 plants and an average capacity of nearly 700 MW. Currently, Son La hydropower plant is the biggest power plant with 2,400 MW installed capacity.

In terms of technology level, gas turbines employ the most advanced technologies as they were built relatively recently. Oil and coal fired power plants, except for recent coal fired power plants, are antiquated with a low plant efficiency of about 27-28% on average. Some of these thermal plants were built in the 1970s, including Ninh Binh and Uong Bi, which are due for retirement.

In terms of power plant distribution, hydro and coal power plants dominate in the North, while in the South gas turbines represent the main power source.

2.1.2 Transmission lines and substations

The transmission assets in Vietnam comprise lines and substations of 500 kV, 220 kV and 110 kV.

- 500 kV lines provide the transmission backbone to enable power exchange between regions,
- 220 kV lines comprise the transmission network within regions, and
- 110 kV lines connect power plants to the network or to the 220 kV substations.

A total length of 4,887 km of 500 kV lines was reported in 2013, whereas a length of 12,166 km and 15,602 km were reported for the 220 kV line and 110 kV lines respectively. The transmission network currently provides electricity to 100% of districts and 97% of all rural households of Vietnam (EVN, 2014).

Transmission lines and substations are presented in the table below:

Table 1: Existing national transmission lines and substations (up to 2013)

No	Asset classification	Voltage		
		500 kV	220 kV	110 kV
1	Network (km)	4,887	12,166	15,602
2	Number of substations	34	175	898
	Capacity of substations [MVA]	19,350	31,202	35,653

2.1.3 Targets for power generation until 2020 with outlook to 2030

Generally, once every five years the Power Development Plan (PDP) is being adjusted and issued anew. The most recent PDP VII was approved by the Prime Minister with the decision No. 1208/QD-TTg, dated 21 July 2011. In this PDP VII, the electricity demand of Vietnam was forecast for the period 2011 to 2020, with an outlook to 2030.

The PDP VII forecasts the electricity demand using an annual average growth rate of 10% from 2011 to 2030. Accordingly, the electricity demand in 2030 should be roughly seven times the 2010 level.

To meet the predicted electricity demand of 194 to 210 billion kWh in 2015; 330 to 362 billion kWh in 2020; and 695 to 834 billion kWh in 2030, additional generation capacity has been planned.

- By 2020, total installed capacity should reach 75,000 MW, of which hydro power accounts for 23.1%, pumped storage hydro power accounts for 2.4%, coal for 48.0%, and gas combustion power for 16.5% (of which LNG power accounts for 2.6%); power from renewable energy sources accounts for 5.6%, nuclear power accounts for 1.3% and imported power accounts for 3.1%.
- By 2030, total power plant capacity should be about 146,800 MW, of which hydro power accounts for 11.8%, pumped storage hydro power for 3.9%; coal thermal power for 51.6%; and gas fired power for 11.8% (of which LNG accounts for 4.1%); power of renewable energy 9.4%; nuclear power 6.6% and imported power 4.9%.

Hydropower is expected to reach its upper capacity limit by 2017, with currently feasible re-sources exploited. Thus newly added capacity after 2015 falls into the category of domestic and imported coal thermal power plants. By 2020, total installed capacity from coal would reach 35,600 MW increasing to 75,000 MW by 2030. Nuclear power plants are planned to be added to the system in 2020, and by 2030 they are planned to contribute 10,700 MW to the grid.

In terms of renewable energy, wind power would be the main contributing technology. According to the PDP VII, the targets for wind power are 1,000 MW by 2020 and 6,200 MW by 2030.

2.1.4 Management and current electricity prices

Up to now the political guidance and direction in terms of electricity planning, power plant development, electricity regulation, competitive electricity market, and electricity tariffs (wholesale and retail for different types of customers) have been uniformly managed by MoIT. The following Figure illustrates the different responsibilities.

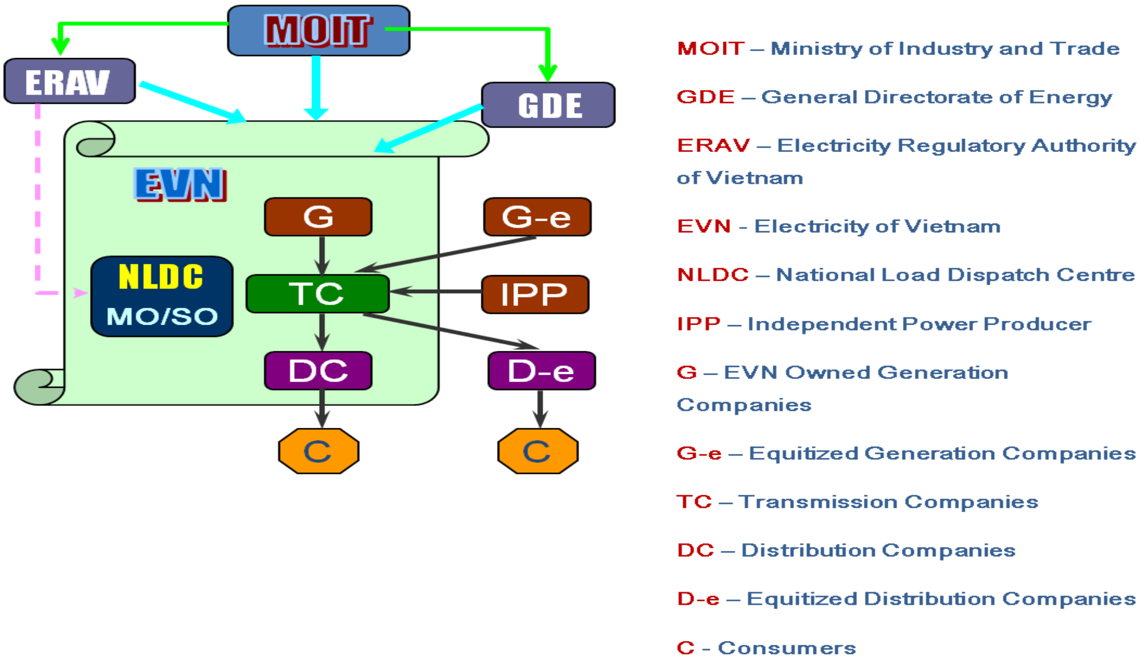

Figure 3: Institutional framework of the electricity sector

The average electricity selling price of Vietnam continued to increase during the past 10 years (2004 – 2013). In the 6-year period from 2004 to 2009, the average increase was 3.8% p.a.; from 2010 up to now, however, the average growth rate increased to 9.5% p.a. By 2013, the average electricity price increased 1.43 times compared to 2010 and nearly doubled compared to 2004 (see Figure 4 below).

According to Decision No. 1208, Vietnam's electricity price will increase and approach the marginal cost of the electricity system of approximately 9 US Cents/kWh in 2020. The goal of electricity price adjustment is to reach establish a competitive electricity market while safeguarding economic and social development objectives.

The competitive electricity market is developed to ensure that electricity price will reflect and recover all costs of the electricity producers as well as reasonable profits. Furthermore, the competitive electricity market is expected to promote energy efficiency, renewable energy as well as to reduce the dependency on imported fossil energy.

To accomplish this goal, electricity tariffs are continuously adjusted. Three main factors that effect to electricity price adjustment are: fuel prices, exchange rates and the power generation mix. Furthermore, the electricity tariff is adjusted according to the various customer groups (households or industry) and regions (urban and rural areas).

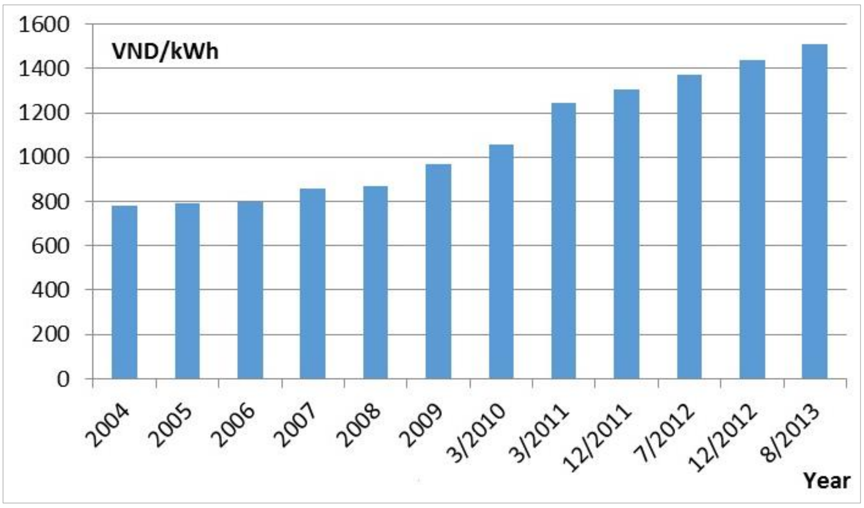

Figure 4: Increasing average electricity system price in the period 2004-2013 (unit: VND)[8]

2.2 Wind power development

2.2.1 Wind power potential assessment

Although the wind potential in Vietnam is considered favorable, there is no comprehensive and appropriate national plan in place to promote the deployment of wind energy.

In early 2010, MoIT (supported by the World Bank) awarded a contract to AWS Truepower to create a new Wind Resource Atlas of Vietnam. The main goal of this project was to update the previous Wind Energy Resource Atlas of South East Asia (2001) using state-of-the-art methods verified by the latest available wind measurements. In addition, the project aimed to make the wind resource maps available to developers and other interested groups through an interactive website.

Based on the data collected from three wind measurement stations in the central coastal region, data from meteo stations and the meso-scale modelling, the wind atlas for Vietnam was updated in 2011. Furthermore, the total wind resource potential of Vietnam has been re-estimated (see Figure 5 and Table 2).

[8] Exchange rate dated 21 Apr. 2014: 1 USD=21,080 VND

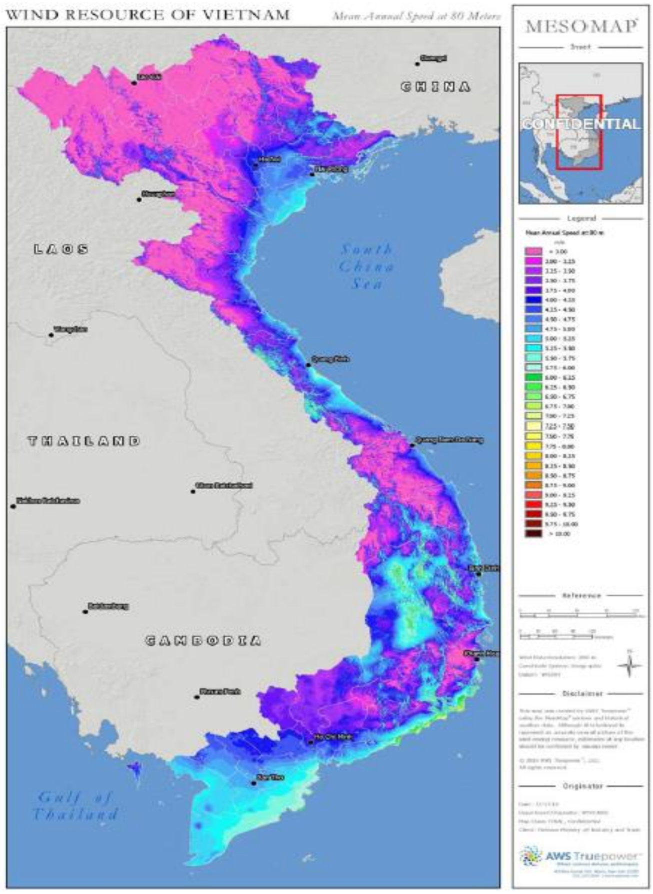

Figure 5: The potential of Vietnam's wind power at the height of 80 meter

Table 2: Potential areas for wind energy use for different wind speeds (TrueWind Solutions, 2001; AWS Truepower, 2011)

Average wind speed (m/s)	<6	6-7	7-8	8-9	>9
Area (km^2) - updated version 2011 (MoIT/WB, 80m)	207,257	2,435	220	20	1
Area (km^2) - older version 2001 (WB, 65m)	197,242	100,367	25,679	2,187	111
% difference between new and old assessments	+ 5.1%	- 97.6%	- 99.1%	- 99.1%	- 99.1%

According to the 2001 World Bank report, the potential area for wind energy use is estimated to be more than 325,000km^2; out of this total area, the share with wind speeds above 6 m/s is 39.4%. Table 2 shows that compared to the 2001 predictions, the estimations for the total potential area for wind energy use at low wind speeds below 6 m/s has increased by approx. 5%. The potential at higher wind speeds, however, is estimated significantly lower in the 2011 report, with a decrease of the potential area of 97.6-99.1%.

Database for wind power potential assessment

Although the wind atlas for Vietnam is available, the reliability and quality of wind data remains questionable due to limited data sources for the simulation. Currently wind data is collected from different studies as well as from institutional information sources:

- Hydrological stations (approx. 150)
- A World Bank study with 3 wind measurement stations in 3 provinces

- EVN studies (2007) at six sites (North, Center and South) for one year and repeated for another year but in other locations.
- Other government agencies including IoE, PECC3 and PECC4: 12 stations
- Project developers' studies
- GIZ/MoIT wind measurement campaign (2010): 10 wind measurement stations in 8 provinces.

According to the wind speeds recorded in the investment reports and projects (27 document/questionnaire sets collected) the average wind speed/year ranges from 5.5 m/s to 7.3 m/s. Although wind measurements are performed by many different individuals and organizations in Vietnam, the access to the data remains very limited. This fact makes it difficult to conduct an appropriate wind power development planning.

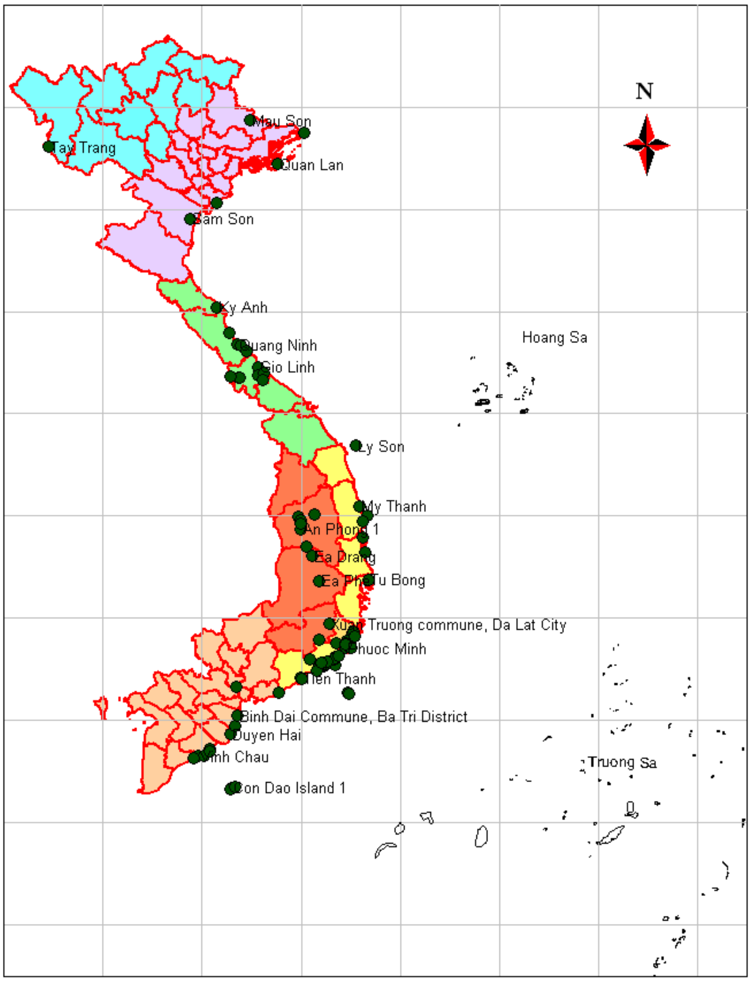

Figure 6: Location of measuring masts in Vietnam (GIZ/ WB 2011)

2.2.2 Existing policy for wind power projects

Before Decision 37/QD-TTg became effective, renewable energy projects received support from a financial incentive mechanism specific to power projects; apart from benefiting from general investment incentive policies. There are numerous legislative documents such as Decisions and Circulars applicable to wind power projects, which are described in more detail in the long version of the study report. For the revision of the current FIT regime, Decision No. 37/2011/QD-TTg and Circular No. 96/2012/TT-BTC are the most important because they relate directly to the buying price of electricity from wind power plants.

Apart from policies and mechanisms for wind power mentioned above, Vietnam is gradually improving its policies to support the localization of high technologies (local content), including wind power technology. Appendix 1 of Prime Minister's Decision No. 49/2010/QD-TTg dated 19 July 2010 (item 42: "Renewable energy transformation and storage technologies") contains a list of high technologies prioritized for development. Some incentives and support applying for the manufacturing of wind towers and auxiliary parts of wind turbines are stipulated in the law as follows:

- Wind power equipment manufacturers can receive the highest incentive level according to the law on corporation tax, VAT, export-import tax;
- The owners of projects on "research and development, application of high technologies" can benefit from land use fee exemption or land use tax reductions in accordance with law on land, etc.

So far, only one private enterprise invests in the manufacturing of steel wind towers and is benefiting from the above mentioned incentives. However, the quantification of these incentive levels is not addressed in this study because of limited availability and access to data concerning this topic.

2.2.3 Current status of the development of wind power projects in Vietnam

Due to a lack of strong and close coordination processes on different management levels (on provincial and national level), the information and data on wind power projects in Vietnam vary greatly according to information source. While some reports predict around 77 projects with a total capacity of 7,234 MW by 2012 (PECC3, 2012), IoE identified only 60 projects in preparation by the end of 2013.

After a respective revision by IoE in April 2014, the total number of projects having applied for registration was 52 with a total capacity of about 4,500 MW (see Table 3) distributed over 14 provinces. Binh Thuan and Ninh Thuan provinces are the ones with most registered projects, amounting to about 50% of the total potential installation capacity of all provinces. Among the 52 projects there are 14 in the stage of preparing pre-feasibility studies (Pre-F/S), 21 completed the feasibility study (F/S), and three projects are in operation. The remaining projects are at the stage of applying for survey, conducting wind speed measurements and preparing investment reports.

Table 3: The number of registered wind power projects

Province		No of projects	Capacity [MW]
1	Bình Định	3	112
2	Phú Yên	2	50
3	Ninh Thuận	13	1067.5
4	Bình Thuận	15	1182
5	Gia Lai	1	40.5
6	Lâm Đồng	2	300
7	Bà Rịa-Vũng Tàu	3	118
8	Tiền Giang	1	100
9	Bến Tre	2	280
10	Trà Vinh	2	123
11	Sóc Trăng	5	480
12	Bạc Liêu	1	99
13	Cà Mau	2	300
Total		**52**	**4452**

Until now, there are three wind power projects in operation on industrial scale in Vietnam (Figure 7), which are located in Binh Thuan and Bac Lieu provinces. With these three projects in operation, the total installed capacity of wind power in Vietnam reaches 52 MW. The projects are receiving varying financial incentives, e.g. provided according to Decision No. 37/2011/QD-TTg and Circular No. 96/2012/TT-BTC.

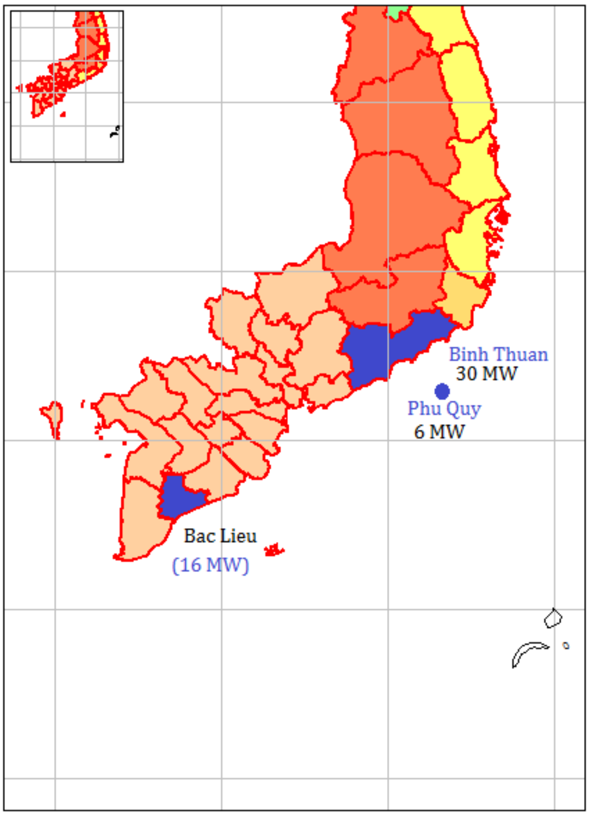

Figure 7: The wind power plants installed and operating in Vietnam

The first onshore wind farm in Vietnam, which is owned by the Vietnam Renewable Energy Joint Stock Company (REVN) in Binh Thanh commune, Tuy Phong district, Binh Thuan province, has completed the first phase of installation with an installed capacity of 30 MW, with 20 wind turbines with a capacity of 1.5 MW each. In the second phase, the project plans to increase its capacity to 120 MW. The project investment volume amounts to VND 1,450 billion (equivalent to approx. USD 60 million). Wind turbines are supplied by the German Fuhrländer company. The connection to the national grid started in March 2011. REVN stated that the project power output in 2011 reached 54,906 MWh; 54,458 MWh in 2012 and 46,073 MWh in 2013. For the early stage of power production from January to June 2011, the project received VND 38.33 billion (USD 1.82 million) from the Vietnam Environment Protection Fund (VEPF). Since then, the project has not received the 1.0 US Cent/kWh government support, as the VEPF has run out of funding and is looking for additional resources from the government. As a result, instead of the expected FIT of total 7.8 US Cents/kWh, the project is currently receiving only the electricity buying price of 6.8 US Cents/kWh from EVN.

The second wind power project, which is on the Phu Quy island, Binh Thuan province, is a hybrid project of wind and diesel generated power. This project, implemented by the PetroVietnam Power Corporation and belonging to the PetroVietnam Group, has the capacity of in total 9 MW; with 3 wind turbines of 2 MW each (Vestas technology) and 6 diesel generators of 0.5 MW each. The installation has been completed and the plant is connected to the national grid since 2012. Total investment cost amount to VND 335.2 billion (around USD 16 million). Due to higher investment and construction cost on islands, the electricity sale price has been proposed by the project investor to be 13 US Cents/kWh. However, this price is not approved and the FIT of 7.8 US Cents/kWh is still applied. 900 MWh were generated in 2012 and 2,500 MWh in 2013.

The third wind power project is owned by the Vietnamese Cong Ly Trade and Service Ltd Company and located in the Mekong Delta of Bac Lieu province. In a first phase, 16 MW were installed in early 2013 (10 turbines with 1.6 MW each, GE technology) and the farm was connected to the national electricity grid in May 2013. As it was constructed on the water edge, the project is identified as “nearshore” and has received an electricity buying price of 7.8 US Cents/kWh at the early stage. Currently, the Cong Ly project receives 9.8 US Cents/kWh. Wind power output in 2013 reached 15,929 MWh and 15,610 MWh was sold to EVN. Until 31 March 2014, wind power output reached 29,267 MWh and 28,682 MWh has been sold to EVN. For the second phase, a total installation of 120 MW is planned. Total investment costs are forecast to reach approx. 5,127 billion VND after the second installation phase[9].

Current status of wind power planning

Under the direction of the Prime Minister in the document No. 3187/VPCP-KTN dated 23 April 2013 on national wind power development planning, MOIT has issued document No. 4308/BCT-TCNL dated 17 May 2013 on procedures and regulations for developing the provincial wind power planning. The documents have been sent to the People's Committee of 24 provinces, which are estimated to have a good potential for wind power development and do not yet have a provincial wind power plan.

By way of the document from MOIT, the provinces are requested to assess their wind power potential. In addition they are requested to prepare provincial wind power development plans and submit them to MOIT. On that basis, MOIT could potentially prepare and submit the national wind power development plan to the Prime Minister for consideration and approval.

On the one hand, the national and/or provincial wind power development plan could help investors and project developers in identifying the most suitable areas for project development. On the other hand, the provincial plans could contribute to an efficient policy-making process and management of national energy resources. Given that the data collected by private companies in the framework of project preparation (FS, PFS) are not available to the provinces, the provinces would have to conduct the wind measurements themselves, which is quite costly.

Until now, only two provinces of Binh Thuan and Ninh Thuan have published a wind power development plan for the period up to 2020, with the vision up to 2030. Other provinces such as Quang Tri, Thai Binh, Soc Trang, Bac Lieu, etc. are still conducting wind measurements and are preparing development plans for wind power. They are expected to be submitted for approval by the Ministry of Industry and Trade in 2014 and 2015.

[9] All of wind power output data for the 3 projects above were collected by questionnaires.

3 International trends in wind energy

Wind energy is considered a mainstream electricity generation source as it is already cost competitive with conventional power in countries such as Australia, Brazil and some areas of the United States (OECD/IEA, 2014). About 80 countries have commercial wind power installations and new projects are being developed wherever conditions are conducive. This means favorable wind speeds and appropriate topography, as well as country-specific technology support policies.[10]

3.1 Global wind market development

The global wind energy market has experienced an accelerated growth of around 25% per year over the last decade (OECD/IEA, 2013). Installed wind capacity increased from 31 GW in 2002 to 282 GW by the end of 2012, adding up to 2.3% of global power generation in the same year (WE Council, 2013). For instance, wind energy provided about 30% of electricity consumption in Denmark, 20% in Portugal, 18% in Spain, 15% in Ireland, 8% in Germany, nearly 4% in the United States and 2% in China in 2012 (OECD/IEA, 2014).

This rapid increase has mainly been due to innovations in turbine technology[11] and improved siting, achieving increased capacity factors of up to 45% (OECD/IEA, 2013). Figure 8 illustrates the deployment of installed capacity broken down by the top ten markets, which accounted for more than 85% of global capacity in 2012 (REN21, 2013).

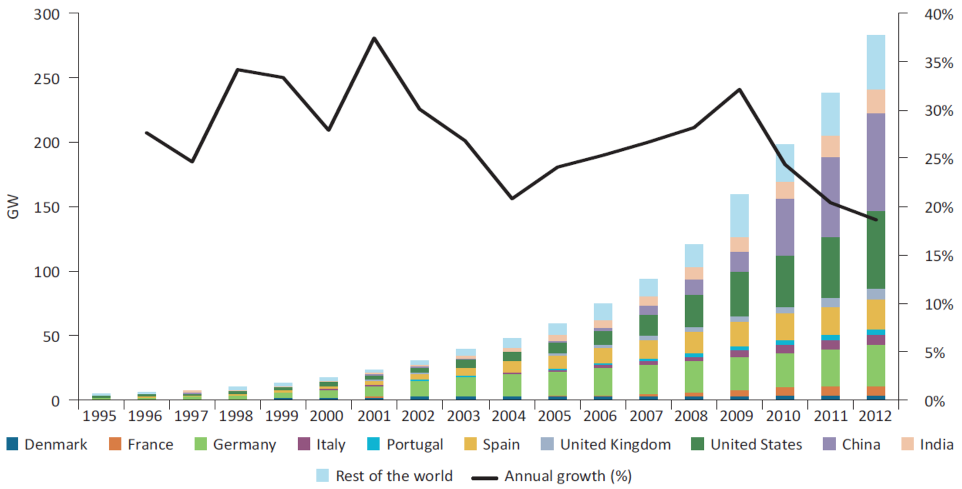

Figure 8: Global cumulative growth of wind power capacity (OECD/IEA, 2014)

Future deployment

According to the 'New Policies Scenario'[12] of the World Energy Outlook 2013, developed by the International Energy Agency (IEA), wind makes the largest contribution to the cumulative global renewables capacity between 2013 and 2035 with total additions of almost 1,250 GW at an annual

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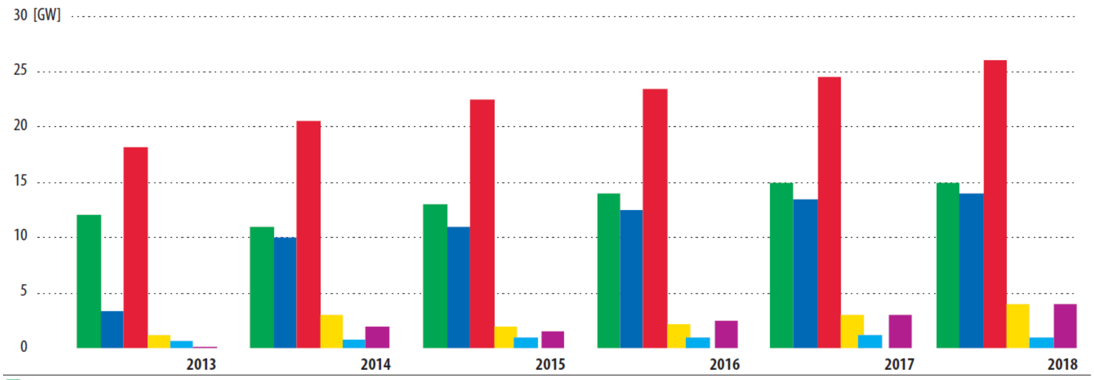
[10] Note: In this short version of the study, only an abbreviated overview of international trends is provided. More details are available in the full report.

[11] The average turbine size has increased from 1 MW in 2002 to 2-3 MW in 2012 by the development of larger rotor diameters and higher hub heights (OECD/IEA, 2013).

[12] The New Policies Scenario incorporates the policies and measures that affect energy markets and that had been legally enacted as of mid-2013. It also "takes account of other relevant commitments that have been announced, even when the precise implementation measures have yet to be fully defined" (OECD/IEA, 2013).

growth rate of 6%. Figure 9 below illustrates a near-term market forecast by region (not differentiated by on- and offshore).



	2013	2014	2015	2016	2017	2018
Europe	12.03	11	13	14	15	15
North America	3.06	10	11	12.5	13.5	14
Asia	18.22	20.5	22.5	23.5	24.5	26
Latin America	1.24	3	2	2.2	3	4
Pacific	0.66	0.8	1	1	1.2	1
Middle East and Africa	0.09	2	1.5	2.5	3	4

Figure 9: Annual market forecast by region 2013-2018 (GWEC, 2013)

According to estimations made by the Global Wind Energy Council (GWEC), global wind power markets will continue to be dominated by Asia, Europe and North America. Furthermore, countries like Brazil or South Africa are expected to increase deployment and move up the ladder of market rankings over the next years. However, the largest contribution will have its origin in China where wind installations totaled to a number of about 16 GW in 2013.

3.2 International cost trends

Wind energy is one of the most cost-effective technologies in terms of cost per kWh of electricity generated. Total costs are determined by capital costs, operation and maintenance costs and the expected annual energy production. The specific values for each category are influenced by different factors such as wind turbine capacity, labor costs, wind speeds and can therefore vary significantly depending on the country and project characteristics.

3.2.1 Capital costs

Turbine costs are the major determinant of the capital cost (CapEx; see Figure 10). They account for 65% to as much as 84% of the total capital costs of onshore wind farms including production and transportation of components, as well as the installation of the rotor, nacelle with gearbox and generator, tower and transformer (IRENA, 2012). Remaining capital costs correspond to the following:

- Grid connection costs: substations and buildings and the connection to the local distribution or transmission grid (cabling);
- Construction costs: foundation and infrastructure, including roads and site preparation;
- Other capital costs: development and engineering costs such as licensing procedures, consultancy and monitoring systems.

Compared to onshore installations, offshore wind parks (OWP) face non-linear cost structures due to required foundation structures, maintenance and cabling. These cost components are heavily depending on the geographic location of the plant (wind potential, water depth, and distance from shore). Consequently, grid connection costs, construction costs and other project costs represent a bigger share for offshore installations[13].

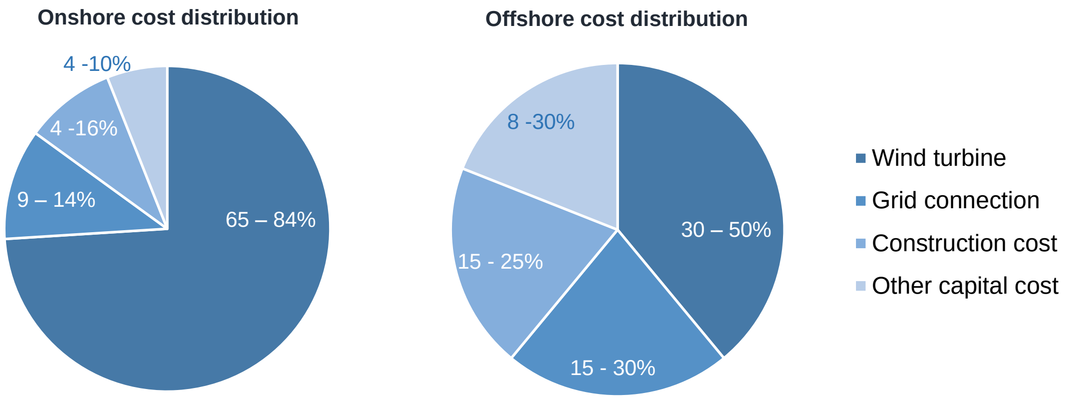


Figure 10: Breakdown of total costs (IRENA, 2013)

For onshore projects, turbine costs account for 30 - 50% of the total capital cost. A combination of several factors has influenced the development of turbine prices (see Figure 11). Between 2004 and 2009, global turbine prices increased more than 60%, reaching an average value of 1,730 USD/kW mainly due to turbine scaling (in order to achieve higher capacity factors), currency movements, labor costs, rising cost for materials, and in some cases, high profit margins for wind turbine manufacturers (Bolinger M, Wiser R., 2012).

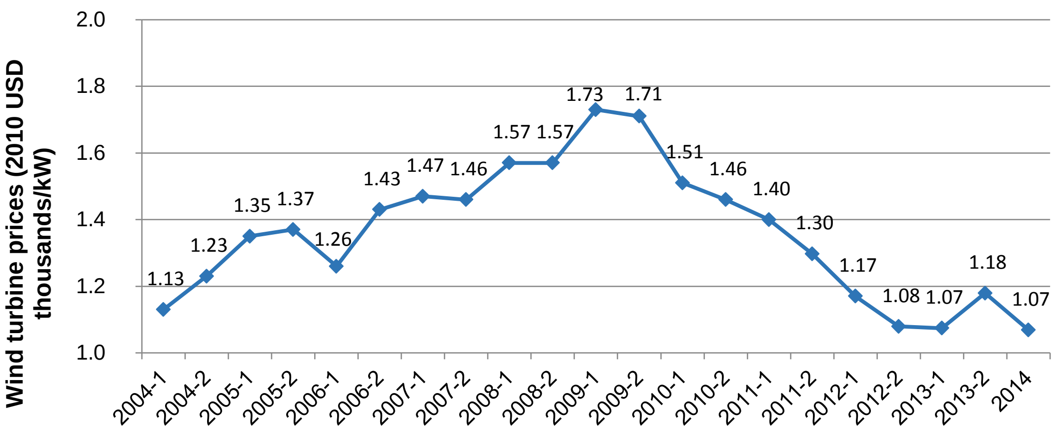


Figure 11: Wind turbine price index by delivery date, 2004 to 2012 (IRENA, 2012, BNEF, 2011)

With a peak in 2009, turbine prices declined as a result of increased competition among wind turbine manufacturers, as well as a temporary decrease in commodity prices for steel, copper and cement (IRENA, 2012; Bolinger M, Wiser R., 2012). However, there has not been a significant reduction of turbine prices in the last two years.

The development of total capital costs (CAPEX) follows a similar pattern to that of the turbine costs (see Figure 12 below).

[13] Grid connection costs for offshore installations may vary significantly among countries.

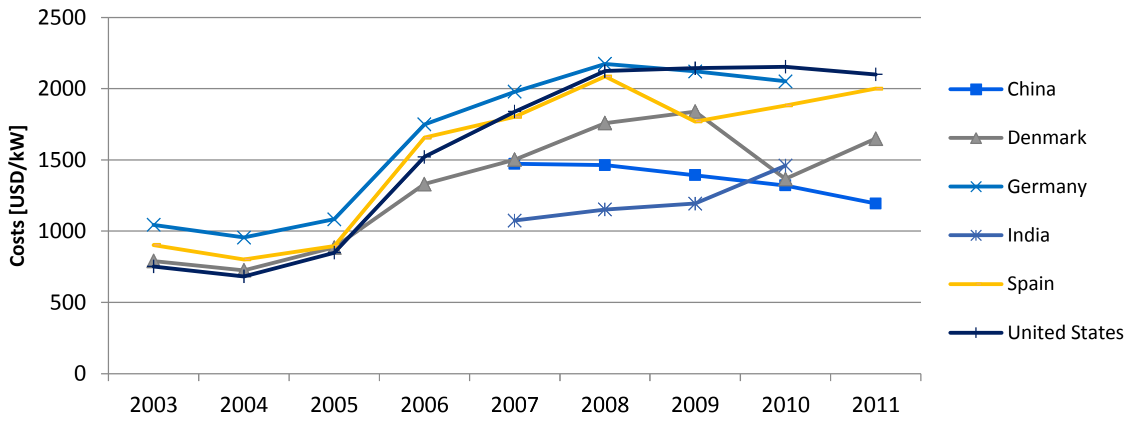


Figure 12: Onshore wind power total capital costs for selected countries (USD/kW) (IRENA, 2012)

Even though average prices in India and Denmark increased slightly in 2010 and 2011 respectively, it is estimated that further reductions will take place in the coming years[14]. The observed upward trend in capital costs per kW between 2005 and 2009 has mainly been due to increased raw material prices (steel and copper) as well as FX movements.

Total capital costs for new projects in 2011 varied from a range of 1,114 – 1,273 USD/kW in China, 1,600 USD/kW in Europe (weighted average costs for new wind projects in European countries) and 2,100 USD/kW in the United States.

Concerning offshore wind parks, it is estimated that the total capital costs are around 2.5 times higher than for onshore installations (values ranging from 3,500 to 6,000 USD/kW) (IRENA, 2013).

3.2.2 Operation and maintenance

Operation and maintenance (O&M) costs for wind technology comprise the cost of wages and materials associated with operating the facility, repair and spare parts, maintenance of the electric installation as well as the land rental. Additional costs such as taxes and insurances are generally not included. Unfortunately, profound information on O&M costs is not as widely available as for capital costs. O&M costs for onshore wind power systems are assumed to decline by 5% by 2015 (IRENA, 2013).

According to the European Wind Energy Association (EWEA), fixed and variable O&M costs of wind power systems typically account for 20% to 25% of the total cost with variability within regions. Typically, O&M costs in the United States as well as in Europe are in the range of 23,000 and 28,000 USD/MW/year. However, lower minimum average costs can be observed for India and China where they amount to about 10,700 – 24,400 and 17,000 – 25,100 USD/MW/year respectively (WE Council, 2013).

Regarding offshore wind power installations, O&M costs are significantly higher (approx. 100,000 to 160,000 USD/MW/year) due to the harsh marine environment and difficult access to the wind turbines. Reducing these costs would considerably improve the economics of offshore wind technology.

3.2.3 Levelized cost of electricity

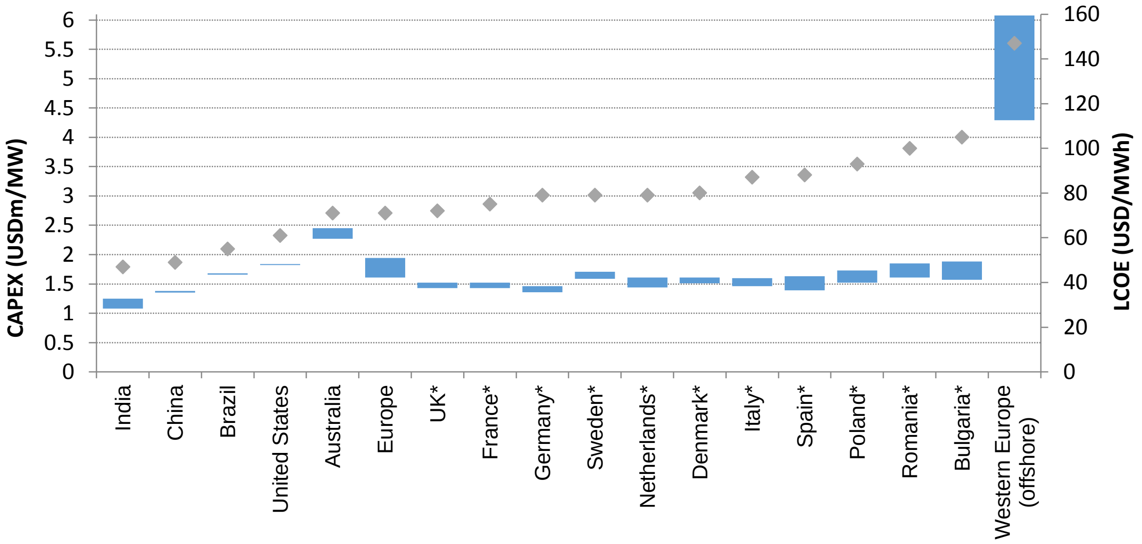
Levelized cost of electricity (LCOE) or also called Levelized Electricity Cost (LEC) calculations can serve as a first indicator to estimate the economic viability of a project. However, a large variability

[14] The International Energy Agency (IEA) and Global Wind Energy Council (GWEC) estimate a potential of cost reductions up to – 18% in the total capital costs to the year 2030 (IRENA, 2012).

within respective estimations can occur due to the respective assumptions. Typically, LCOE take the following variables into consideration: capital expenditures, operation and maintenance costs, generated electricity per year, real interest rate and operational lifetime of the plant.

In accordance with the global capacity deployment, and the aforementioned reductions of capital and operational expenditures, LCOE of wind power has decreased in the last years. Bloomberg New Energy Finance (BNEF) calculated a decline of 18% in LCOE values between mid-2009 and 2013. This trend is expected to continue between 2012 and 2030 as innovation and economies of scale keep on driving down costs. GWEC expects a 35% decrease of LCOE for wind turbines with capacity factors between 25-35% (WE Council, 2012).

The estimated cost of wind power may vary significantly depending on the capacity factors assumed for each project. Capacity factors are determined by the quality of the wind resource and the technical characteristics of the wind turbines, which have to be selected accordingly in order to maximize the energy output. Consequently, there is a wide range of capacity factors within wind projects in a single country.



*CapEx ranges are indicated by the blue bars, while LCOE corresponds to the green dots.

Figure 13: CapEx and Levelized costs for wind energy by country (prices of 2012). (WE Council, 2013)

Figure 13 illustrates the relation between CapEx and LCOE for wind energy per country. For instance, it can be observed that CapEx estimated for most European countries are considerably lower than those estimated for Australia, while their LCOE are in the same range. Moreover, it can be seen that the costs for offshore wind parks are significantly higher than the most expensive CapEx and LCOE for onshore wind (see right hand side of Figure 13).

3.2.4 Experiences on grid connection costs

Alongside the actual cost for the turbine and other materials as well as for the erection and necessary foundation structures, the grid connection costs are of great importance. Obtaining permits with regard to the grid connection and the respective cost-sharing between the project stakeholders can delay the deployment of wind farms and lead to high administrative costs.

Large wind farms are usually connected to the high voltage or medium distribution grid, whereas individual wind turbines or clusters of turbines may also be connected to the low voltage distribution grid.

Generally, power purchasing regulations include provisions for cost sharing between renewable energy producers and grid operators as the costs for grid connection have an important impact on the economic viability of a project. In some cases, the producer pays for grid connection costs, in other cases they are socialized and paid by the distribution company. Hence, various grid connection cost regimes can be identified throughout the various wind energy markets worldwide.

In the case of Vietnam, EVN stated that the electricity grid is currently capable to accommodate capacity additions at any location within the country. EVN makes use of the "shallow charging method", thus the operator only has to pay the grid connection to the nearest grid-connection point. Hence, project developers encounter comparably low grid connection costs within a transparent grid charging system. However, this approach offers only limited incentives for locational signals and developers are depending on the DNO to timely reinforce the grid (c.f. feasibility studies).

3.2.5 Overview on Local Content Requirements

Local content requirements (LCR) are policy measures created with the intention to increase local value and employment creation. These can be regulatory instruments (prescribed standards), market-based instruments or a combination of both to stimulate a desired market outcome. Globally, different forms of LCR have emerged in recent years.

Table 4: Overview on local content requirements (ICTSD, 2013)

Canada (Ontario Green Act)	• FIT associated with 50% local content as of 2012 • Turbine manufacturers are required to provide 30% of local content
Ukraine	• FIT conditional upon local content requirement (50% by 2014)
Turkey	• FIT adder associated to local production of individual turbine parts
Croatia	• Add-on to the basic support up to 15%
Brazil	• Financing from BNDES (promotional bank) limited to companies complying meeting local content requirements
South Africa	• While initially starting with a 25% local content requirement, project developers currently will have to meet a threshold of at least 40% of production to be localized in SA

It is important to point out that the effectiveness of LCR depends on several factors such as

- the innovation potential and domestic capabilities,
- the availability of financing,
- policy design, policy coherence and coordination,
- and especially on the expected market size.

Hence, if the domestic market is very large (India, China), the benefits from having domestic production in terms of employment and future market development, industrialization or spillovers can exceed the disadvantages of producing at either slightly higher prices or slightly lower quality. On the other hand, if the domestic market is rather small, LCR measures can become a barrier to wind technology deployment as the domestic production, once established, would have to participate on international markets with competitive pricing.

The main concerns on LCR are related to its effects on cost-efficiency. Foreign turbine manufacturers may have to invest in production facilities, which are not economically viable in the long run, or acquire local products at higher prices and lower quality than available on the international market. As a result, policy design approaches with LCR may tend to distort the market, raise prices and have a potential to delay, or even hinder investments. This may hold back the potential of wind power to become competitive with conventional technologies.

In this sense, it is of immense importance that before introducing LCR, several basic conditions as, among others, the market size, maturity and capability of the industry, are evaluated. If existent, LCR legislation should set out detailed targets associated to specific components or activities in which it is desired to create local markets. Furthermore, policy makers are advised to attentively assess whether support schemes including local content requirements comply with WTO provisions[15] (ICTSD, 2013).

3.3 International experiences with support schemes

In order to recover costs and to receive revenue on the capital employed, generators are depending on adequate financial remuneration. Therefore, policy mechanisms need to be designed carefully according to the specific country characteristics to ensure efficiency and effectiveness. Generally, mechanisms need to consider a variety of target dimensions. These include the following:

- Offer predictable and stable revenue stream to generators
- Trigger investments in different regions (=avoiding hotspots)
- Adequately control pace of capacity additions (=growth corridor)
- Cost and volume control of forthcoming capacity additions (=fair burden distribution)

Table 5 provides an overview of the support mechanisms that are most commonly utilized in contemporary energy markets.

Table 5: Support mechanisms used in different energy markets (OECD/IEA, 2014)

	Brazil	China	Denmark	Germany	Greece	India	Ireland	Italy	Portugal	Spain	UK	USA
Feed-in tariff	x	x	x	x	x	x	x		x	X	x	
Premium or adder system			x	x						x		
Auction or tendering system	x	x					x			x	x	
Tax based (electricity) production incentives												x
Spot market trading			x	x			x	x		x	x	
Investment subsidy or tax credit			x		x	x						x
Tradable Green Certificate (e.g. REC/ROC)						x		x			x	x
Concessionary finance trough government supported agencies	x	x		x		x				x		x
Concession on import duty	x	x				x						

Most support schemes can be distinguished by being either price- or quantity-based. In the case of a price-based scheme, a national entity (such as a regulator) sets a fixed price (or a price-range) for the generated volume of electricity of a certain renewable technology. This price-setting can

[15] The use of LCR in some countries have led to international trade disputes, however, procurement tenders that contain LCR are not yet disciplined by WTO and may therefore be permissible

then be subject to features such as duration of remuneration, capacity scale of the plant or even location of the plant. Most commonly, operators are eligible to receive a fixed tariff or a premium (usually being referred to as “feed-in tariff” or ”feed-in premium”) for a pre-defined period (e.g. 20 years). In order to facilitate cost-reduction of the technology and hence allow space for learning effects, tariffs may be subject to an annual degression factor (typically between 2-8%; or can be indexed with regards to an inflation rate). To adequately control new installations of plants, support schemes can be designed with respect to a flexible cap that defines a yearly growth corridor.

So far, feed-in tariffs have been deployed in nearly 100 countries and have greatly increased the installation of renewable energies (REN 21, 2014). However, it needs to be acknowledged that in some cases the tariff led to market distortions due to immense fiscal liabilities if not adequately designed. Therefore, it is often criticized that feed-in tariffs do no create cost-effective market development, as experienced in Germany, Spain or Italy. For instance, in less than six years, Italy has become one of the leading markets for PV power plants and one of the countries with the largest number of installations. This tremendous growth has mainly been due to the offered feed-in tariff that has been uncapped until 2012. Any size or any number of PV plants could be installed during a period of three years. Since the FITs are not financed out of the national budget, but are rather levied upon the customers (charged to the electricity bills), Italian electricity customers are now due to pay each year a surcharge of EUR 9 billion (approx. USD 12.3 billion) on their bills (Antonelli, et. al., 2014).

In contrast to the above mentioned price-based design, within quantity-based schemes the volume is being predetermined by a national entity and the price develops according to market conditions. In recent years, especially auction systems have gained popularity due to their comparative advantage in effectively minimizing transaction costs and the costs of regulating the deployment of RE. Generally, auction schemes have the advantage that mismatches regarding the respective tariff height can be avoided. Hence, it offers the opportunity to control the volumes of renewable generation capacity to be commissioned. Countries such as Brazil, China, South Africa or India are undertaking annual bidding rounds where they auction required capacity.

Nevertheless, with regard to auction mechanisms it is vital to find a compromise between incentivizing high deployment rates of renewable energies without reducing the number of market participants. Therefore, the investors within auction scheme regimes point out that not only the actual design of the auction system but also the underlying framework needs to be considered. This includes factors such as: market attractiveness, country specific aspects (general investment climate, economic outlook), PPA arrangements or grid connection aspects.

Besides price- and quantity-based support schemes, further policies may be utilized to facilitate the deployment of RE, such as tax exemptions or investment subsidies. It is common practice that not only one but a mix of instrument will be implemented to support the up-take of renewables along the chain of value creation.

An important aspect while choosing appropriate support schemes is the issue of burden sharing. In the context of increasing policy costs for the support of renewable energies, a fair distribution of the resulting costs (without negative effects for energy-intensive industries) is of large importance. Furthermore, a fair cost-sharing control is key to maintain public acceptance of RE support. Generally, funding for RE support mechanisms may either be financed through a public budget or from a levy that is being socialized over the electricity customers. In Europe, most member states distribute the costs for RE support among all electricity customers by imposing a surcharge on top of the electricity price. In this context, it is important to mention that many countries apply different types of exemptions for energy-intensive industries, since electricity costs represent a significant part of their total expenses. The preferred procedure of energy-intensive industries by granting exemptions or reductions of the respective levy improves the international competitiveness of these industries, but at the same time increases the burden for the remaining consumers.

3.4 Barriers for wind technology deployment

Barriers for wind technology deployment are present in various forms. They can be categorized as:

Technical aspects

During the planning phase, the competition with other land use types and environmental issues are the main concerns. They may be alleviated by adequate planning procedures at a national level and well-designed environmental impact assessment guidelines. Likewise, operational barriers as the opposition of local population and constrained connection to the grid can be mitigated by communication strategies and regulated control for the connection of Independent Power Producers (IPP) (OECD/IEA, 2014).

Economic and financial aspects

Financial and economic barriers include high upfront costs, investor uncertainty and the lack of finance for wind project developers. Alongside the actual cost for the erection and necessary foundation structures the grid connection costs are of importance. So far, issues regarding grid connection and the cost-burden sharing have been a decelerating factor in most countries.

Institutional aspects and market integration

Eventually the integration of large amounts of intermittent electricity generation demonstrates hurdles for contemporary energy markets. Renewable Energy Technologies (RET) are having a large impact on the electricity price at wholesale markets. Several studies have indicated the effect of large amounts of intermittent generation on power pools. Growing wind capacity may thereby decrease wholesale prices (due to very low marginal costs) and lead to higher price volatility (due to fluctuating wind generation).

4 Analysis and review of the existing support scheme and framework

In this chapter we will present the current processes of wind power development in Vietnam, including main implementation steps and the strength and barriers of these processes.

4.1 Qualitative Analysis

4.1.1 Current processes for wind power development

- Pursuant to the Government's Degree No.108/2006/NĐ-CP dated September 22, 2006 on detailed regulation and implementation of special articles under Investment Law.
- Pursuant to the MOIT's Circular No. 32/2012/TT-BCT dated November 11, 2012 on Regulations on implementation of wind power projects development and standardized power purchase agreements for wind power projects.
- Pursuant to the Government's Degree No. 2/2009/NĐ-CP dated February 10, 2009 on Management of construction investment projects.

A general overview of the process of wind power project development is depicted in the figure below. It can vary slightly among provinces.

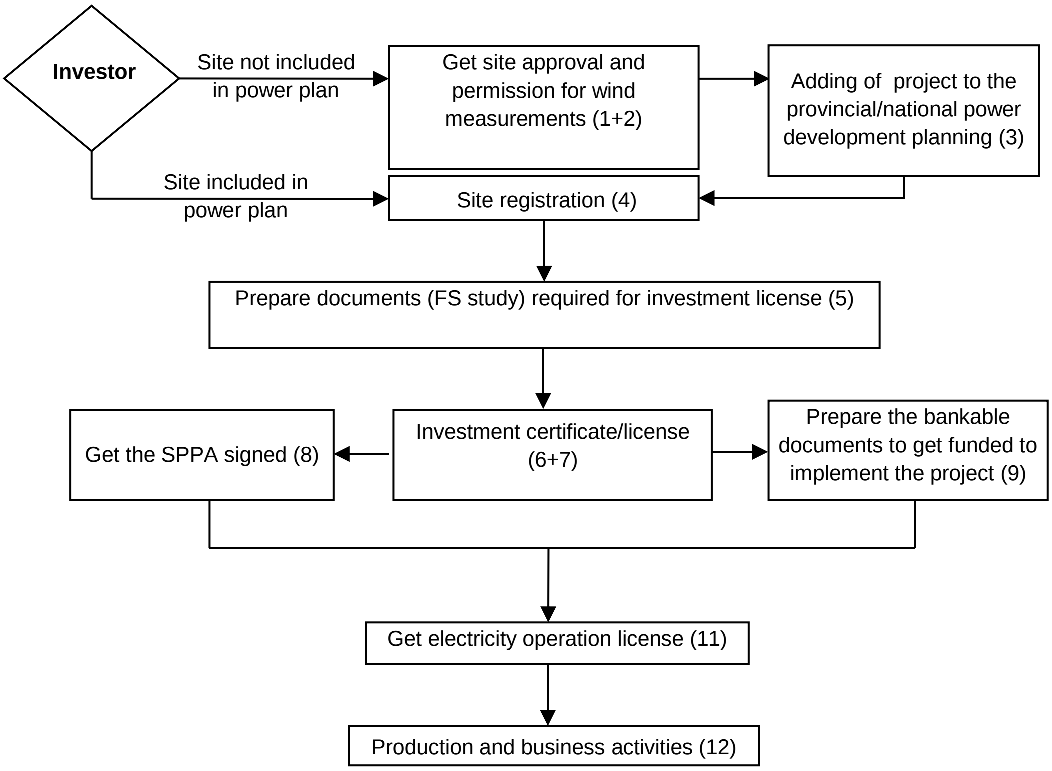


Figure 14: Processes for wind power project development

For projects with a total installed capacity below 50 MW, the Provincial People's Committee (PPC) will publish the list of projects and select project development investors for MoIT's approval. For projects with an installed capacity above 50 MW, MoIT will publish a list of projects and select investors for Prime Minister's approval.

The role and function of related organization and units as well as the required time for implementation of each related task are briefly presented in the following table:

Table 6: Role and function of related organization and units and required time

Steps	The work to be performed	Related Organizations and Units	Required time stipulated by current regulation
Step 1: **Site approval** (if the project in not included in the power development plan/ wind power development plan = 1a)	Investor studies available data to find regions with possible good wind regimes Investor conducts site survey: assess topography, infrastructure and distance from site to grid Based on the primary survey results, the investor registers to PC to obtain permission to conduct wind potential measurement and define investment opportunity for the proposed site. Application for permission includes (i) request letter of investor (ii) basic information of investor, (iii) preliminary information of the study content Investor gets letter of acceptance of site and permission to conduct study assessing wind potential and investment opportunity. Study activities include (i) conducting wind measurement for a minimum of 12 successive months, and (ii) preparing a project investment report.	DOIT sends the document to relevant provincial departments for comments and send to PC for approval PC approves and sends to DPI DPI sends to investor	10 days 10 days 1 day
Step 2: **conduct wind measurement** (applied for 1a)	Investor erects one or more wind measurement masts with sensors for wind speed, wind direction, temperature, pressure etc. at different heights on the approved site. Wind measurement will prolong for at least 1 year.		
Step 3: **Request for inclusion to (wind) power development plan** (applied for 1a)	Based on the wind data analysis, investor sends the request to PC.	Depends on the project volume, the request could be dealt with by PC or MOIT. PC sends to investor the acceptance	30 days
Step 4: **Site registration** (for both project types)	Investor submits the site registration to People's Committee	Prime Minister (nominal capacity greater than 50MW) PC (nominal capacity less than 50MW) Department of Industry and Trade (DOIT) or/and Department of Planning and Investment, depending on provinces	15 days

Step 5: Get investment license and permission for inclusion to the (wind) power development plan	Investor develops the project investment document (FS) include: (i) request of investor; (ii) basic information of investor, (iii) necessity of investment in project construction; (iv) project description; (v) implementation solutions; (vi) environmental impact assessment; (vii) project's total investment cost; (viii) all results of wind measurement and resource assessment; (ix) acceptance paper of EVN to purchase electricity; (x) opinions of Provincial People's Committee on site and land use area; (xi) agreement on grid connection point with regional power company or power transmission units; FS study is sent to DOIT. DOIT sends documents to related provincial agencies (including regional power company or power transmission unit) for comments and sends to PC for appraisal. Category A projects with an investment cost of over VND 1,500 billion fall under the authority of the Prime Minister (~ nominal capacity more than 50MW). MoIT will review them and accordingly inform the Prime Minister, who will then approve the development plan and permit investment principle. For projects under MoIT's authority (~ less than 50MW), the PC will review eligible investment reports and accordingly inform MoIT, which will then approve the development plan and permit investment principle. Based on the investment principles, PC issues the investment license.	PC and DC Regional power company or power transmission units DOIT, DoNRE GDE- MOIT	GDE will approve this document 30 days after receiving the fully eligible documents 20 days
Step 6: Land clearance	The investor prepares necessary steps with communes and local people to conduct land clearance.	PC and local community	
Step 7: Prepare the investment project report	After obtaining the investment license, the investor shall organize preparation of the investment project report, review, and approval of wind power investment-construction project. The investment project dossier consists of the description and basic design, including connection options of the power plant to the national power grid, measurement – control equipment. MoIT comments on the basic design of Category A projects; DoIT comments on the basic design of Category B projects. Investor will decide on investment based on the reviews of the basic design.	MOIT DOIT Regional power company or power transmission unit	

Step 8: Sign the SPPA	Negotiation with power purchasing party based on the power purchasing standard contract for wind projects stipulated in the Annex of Circular 32/2012/TT-BCT dated 12/11/2012 issued by MoIT. The project investor will negotiate and sign the Standardized Power Purchase Agreement (SPPA) with EVN. This is the final step after: (i) signing an MoU on power purchasing, done during the investment report preparation stage; (ii) signing an agreement on grid connection, (iii) negotiating and signing an MoU on power purchasing price; and (iv) signing an agreement on the design of the metering and telecommunication system during the investment project report preparation stage.	Power purchase company under EVN	Not stipulated to a specific deadline
Step 9: Prepare bankable documents and get funded to implement the project	Investor prepares documents for project financing and sends to financial institutions and to MOF/MPI to request for tax redemption.		MOF, MPI
Step 10: Project construction	The project owner prepares, organizes review and approval of the technical design, detailed construction drawings and total cost estimates based on the approved investment project. The project investor may start construction of technical design items only upon approval and once the project has sufficient finance. The investment project shall comply with regulations on construction license, contractor selection, construction work management, project management form, payment, and liquidation contracts following current regulations.	Direct unit of implementation: DOC Authorized unit for decision: PC	
Step 11: Electricity operation license	After a successful commission with acknowledgement of different relevant authorities, the project gets the License of Electricity operation from ERAV	ERAV	
Step 12: Production and business activities			

4.1.2 Barriers to investment within the current processes

At present, only two provinces have completed a wind power planning process and a national wind planning strategy has not been developed yet. This represents an obstacle for investors as they spend a lot of time on very specific agreements in the planning phase, which in other countries are integrated into a nationally applicable framework for all wind energy projects.

Some obstacles in the investment process have been identified from the survey on investment and support mechanisms for wind energy in Vietnam, as well as from feasibility study reports and meetings:

- Due to the lack of wind power planning, the projects are requested to apply for inclusion into the National Power Development Plan. This step is seen as one of the biggest challenges for many investors and project developers due to a complex and unclear procedure which prolongs the whole process. Furthermore, due to the limited capacity of national consultants many documents did not meet the required criteria and could not be approved. The biggest challenges for which the study team proposes an adjustment, supplementary to the power development planning, are: a) “waiting time concerns” and b) “procedure and process”, which have been mentioned by 86% of all survey respondents.
- The lack of close coordination among provincial and national institutions, which are responsible for the same process. Based on the summarized results of the feedback from the questionnaires, the use of land for identified projects overlapped with other land use purposes. The biggest problem in land use was found for resource exploitation (mineral, crops, etc.) in 78% of the time, no land use planning accounted for 33%, mine clearance and lack of local authority support, each 22% and lack of local community support for 11%.
- Wind measurement equipment and auxiliaries had to be carefully safeguarded in order to ensure the safety and prevent errors caused by attitudes and behaviors of local residents during wind measurement time.
- A lot of projects lagged behind the proposed schedule because of a delay in financial closure and difficulties in finding financing sources due to the current low level of the FIT for wind power. The capital requirements for wind power projects are rather high and the absence of a guarantee fund as well as the complexity of project evaluations often exceed the capacity of a domestic commercial bank.
- As the Vietnamese wind power market is very young, there are only limited partnerships and services. In the process of setting up the pre-feasibility study and feasibility study, the major obstacle for project developers is to identify an experienced partner in the field of grid connected wind power in Vietnam. Another very important issue in project development is to select a suitable type of wind turbine, which can cope with the harsh climate regime of Vietnam (gusty winds, including typhoons; heat; humidity; dust).

In general, when developing a wind power project in Vietnam, the investors / project developers face different issues such as lack of information on wind power planning; overlapping land use planning; unsecure and unreliable wind measurements; difficulties in funding; limitations of consulting capacity; slow licensing procedures and an inadequate support mechanism for wind power. In particular, the study revealed that the main difficulties from an investor’s point of view for the investment and construction of grid-connected wind power are: security and reliability of wind measurements (24% of survey respondents); inadequate support mechanism for wind power (20%); overlapping land-use planning (18%); slow licensing procedures (18%). In addition, the issues on limitations of consulting capacity (9%) and difficulties in funding (7%) have been mentioned.

Up to now, two grid connected wind power plants are in operation in Vietnam. Apart from the issues mentioned above, obstacles during project implementation of these two plants included the country's weak infrastructure (roads, bridges and sea port), which is often unsuitable for the transport of long and heavy components. Furthermore, some machines and equipment for wind farm construction (such as a sufficiently large crane) were not available and had to be hired from other countries.

All in all, these factors lead to comparably high investment costs for wind power projects in Vietnam, with respective impacts on the risk premium that investors will place on their expected IRR and a resulting requirement for an adequate support mechanism to (partly) mitigate these risks.

4.2 Quantitative Analysis

4.2.1 Adequacy of the current FIT

The current tariff for the onshore grid-connected wind power projects is 7.8 US Cents/kWh paid by two entities. While the "electric buying price" of 6.8 US Cents/kWh are paid by EVN (single power purchase buyer), the remaining 1.0 US Cents/kWh (called "state support electric price") is supposed to be paid by the Vietnam Environment Protection Fund (VEPF). EVN finances the payments to wind power investors by including costs in the electricity system price. However, funds covered by VEPF, which are taken from an annual state budget, are very limited and often not available for wind power projects. As a result, rational wind project developers base their cash flow models on revenues of 6.8 US Cents/kWh; not 7.8 US Cents/kWh.

Consequently, while the study team recognizes that the official FIT is 7.8 US Cents/kWh, the calculations for funding requirements for the proposed FIT of 10.4 US Cents/kWh are based on 6.8 US Cents/kWh throughout the document.

Based on the detailed analysis of the quantitative factors affecting the FIT, the study team concluded that the FIT of 6.8 US Cents/kWh will not lead to the desired effects, and at best open the market to a very small number of investors. These investors are characterized by the following attributes:

(i) Accept a very low project IRR of 6% and below
(ii) Can access debt funding below standard market conditions e.g. by **Official Development Assistance** (ODA) funding or
(iii) Are able to perform a balance sheet financing of the project. The project liabilities are backed by other funding sources of sufficient credit quality.
(iv) Have a strong strategic view on long term infrastructure investments in general, and wind power development in particular, without a strong requirement on the economic performance.

4.2.2 Description of data set

The analysis of the current situation of the Vietnamese wind power market is based on two types of data sources: Firstly, on feasibility and pre-feasibility studies (FS) carried out by potential project developers, and, secondly, on interviews and questionnaires (Q) conducted among project developers by the Institute of Energy as part of the study. Within the study, a well-diversified set of 23 different wind farm projects in six different provinces with a combined potential capacity of 1,169 MW was examined. The projects deploy or intend to deploy technologies from nine different turbines manufactures from Europe, USA, Argentina and China. Two of the wind farms, Tuy Phong 1 (2010) and the nearshore project Cong Ly (2013), are already in operation.

The following Table summarizes the capacity of each wind farm, the province it is located in and the data source for the respective project.

Table 7: Scope of data set - 23 projects from six different provinces were analyzed.

Num.	Project	Province	Cap. in [MW]	Source
1	An Phong	Ninh Thuan	70.00	FS/Q
2	Phuoc Hai	Ninh Thuan	97.50	FS/Q
3	Vin Chau	Soc Trang	28.80	FS/Q
4	Phu Lac	Binh Thuan	24.00	FS/Q
5	Phuong Mai	Binh Dinh	21.00	FS
6	Bac Binh	Binh Thuan	69.00	FS
7	Hoa Thang	Binh Thuan	98.70	FS
8	Mien Dong	Binh Thuan	42.00	FS
9	Phuoc The	Binh Thuan	30.00	FS
10	Quang Tri	Quang Tri	28.90	FS
11	Sai Gon	Binh Thuan	199.50	FS
12	Tien Thanh	Binh Thuan	51.00	FS
13	Tran De	Soc Trang	29.90	FS
14	Trung Nam	Ninh Thuan	35.00	FS
15	Tuy Phong 2	Binh Thuan	43.50	FS
16	Van Thanh	Binh Thuan	40.50	FS
17	Bac Lieu	Bac Lieu	83.20	FS
18	*Tuy Phong 1	Binh Thuan	30.00	Q
19	Nhon Hoi	Binh Dinh	30.55	Q
20	Phuoc Huu	Ninh Thuan	50.00	Q
21	Duyen Hai	Ninh Thuan	19.80	Q
22	Mui Dinh	Ninh Thuan	30.00	Q
23	*Cong Ly	Bac Lieu	16.00	Q
		SUM	**1,169.00**	

Content of data set

To analyze the current tariff situation, the following information was analyzed more closely: Wind farm location and wind conditions, turbine specification and planned electricity production, capital expenditure (CapEx) and cost of operations (OpEx), financing conditions and the projected tariff. CapEx costs are considered to be all-in cost, including all components. Exogenous factors like tax rates, FX rates (21,090 VND per 1 USD) and the emission factors of the grid (0.644 tons CO2/MWh) are assumed to be constant for all projects to allow for a better comparison. The collected information is sufficient to calculate a financial model for each project.

In the following, an assessment of the tariff and a comparison of various projects are provided.

4.2.3 Methodological approach to analyze the current FIT level

An important criterion to assess the current situation of wind power development and the adequacy of the current FIT is the calculation of the Levelized Electricity Cost (LEC) for the given project portfolio. The LEC are the cost for electricity generation and are generally presented as specific costs per unit of energy (kWh) produced over the life time of the project. The LEC is affected by three key factors:

(i) **Time value of electricity production over life time of the park**

This factor is the discounted total electricity production in kWh of the entire operation period of the wind farm. It implicitly assesses the quality of the site and the wind farm design. The basis of the calculation is the annual net wind farm output at the P50 production level: with a probability of 50%, this level of electricity production will not be undercut in any given year of operation. A conservative estimate of this figure considers the projected energy production excluding scheduled and unscheduled maintenance time and any other losses due to technical or physical conditions. The period of operation of a wind farm is assumed to be 20 years.

(ii) **Capital expenditure (CapEx) of wind farm**

The definition of CapEx in this context describes the total capital expenditures for the construction of the wind park, including equipment, labor, infrastructure and transaction cost, interest rates during the construction phase, and all fees.

(iii) **Time value of operational expenses over life time (OpEx) wind farm**

The calculation of this factor requires the estimation of the complete time series of the operational expenses. In our definition, OpEx include maintenance, insurance and administrative cost as well as costs for land lease, own electricity consumption of the wind farm and for decommissioning. The period of operation is assumed to be 20 years.

The pre-tax LEC is represented by the sum of capital expenditure and present value of total OpEx of the entire operation period of the wind farm, divided by the time value (present value) of total electricity generated (LEC = (ii+iii)/i):

$$LEC(r_P) = \frac{\text{CapEx} + PV_{OM}(r_P)}{PV_{Elec}(r_P)} \qquad (1)$$

The LEC is a function of the return rate $\mathbf{r_p}$, which serves to discount future expenditures and electricity production. Both OpEx and the electricity generation of the wind farm are taken over an operations period of 20 years. In order to assess the present value of the cash flows and the generation of the wind farm at time of planning, they are discounted with $\mathbf{r_p}$.

The present value of OpEx and the electricity production is the sum of the discounted values of the time series T= 0,…, N – with N=20 years - and is calculated as follows:

$$Present\ value(r_P) = \sum_{T=0}^{T=N} \frac{\text{Value}(T)}{(1+r_P)^T} \qquad (2)$$

4.2.4 Analysis of LEC and key factors of sample wind parks

In the following the LEC for the present wind park portfolio are analyzed. The LECs are calculated for three different values of the target project Internal Rate of Return (IRR), representing the annual return that investors can expect. In the study, IRRs of 6%, 10% and 16% are explored, covering a wide range of investment conditions and representing three different investor types that are explained in more detail below:

(i) **Highly subsidized investment:** The investor has either access to highly subsidized funding, e.g. debt funding at interest rates of 1-2% and can therefore accept a moderate project return of just 6%, or follows other goals that are not driven by economic factors. Examples include debt provided by international financing institutions e.g. via KfW in combination with equity provided by the public or investments of the public and private sector. It could also involve investors that do not rely on debt funding but have other funding resources like balance-sheet funding or internal funding. The selected pre-tax project IRR of 6% is a typical hurdle rate for internal project approval by an investor with access to subsidized funding.

(ii) **Strategic investment:** The investor accepts project returns that are in the range of typical debt levels of about 10% as internal hurdle rate. The investor is not purely driven by medium-term economic factors but seeks long-term income producing assets with moderate return. This investor group could involve turbine manufactures that have a strategic interest to enter the Vietnamese market or pension funds that have a strong focus on a long-term investment horizon. They are assumed to secure debt financing at rates of 6%.

(iii) Commercial investment by international or local investor: This investor type has to rely on debt funding at interest rates in the range of 10% or above and therefore requires a competitive risk premium. In order to realize a return consistent with the debt levels, the investor requires project IRRs of about 16%. Typical examples are international investors like infrastructure funds.

In the following section, strategic investors with an expected pre-tax project IRR of 10% are assumed to represent the reference case as their required IRR lies in the middle of that of the two other investor types. The underlying project currency is assumed to be USD. Debt funding is always consolidated in USD; however, local commercial loans may be denominated in VND. Interest rate levels for these loans are therefore derived from local project finance conditions provided by local commercial banks.

In the next step we explore the LEC and capacity factor with respect to a regional break-down. Table 8 shows the average LEC and capacity factor for projects from each province represented in this study.

Table 8: Average capacity factor and LEC values by provinces[16]

Province	Samples	Capacity	LEC(6%)	LEC(10%)	LEC(16%)
Bac Lieu	2	31.73%	9.73	12.45	17.09
Binh Dinh	2	34.58%	7.28	9.18	12.40
Binh Thuan	10	26.90%	8.65	11.10	15.25
Ninh Thuan	6	31.22%	8.22	10.59	14.61
Quang Tri	1	29.73%	8.12	10.42	14.30
Soc Trang	2	33.91%	7.53	9.85	13.76
Average	**23**	**29.85%**	**8.39**	**10.78**	**14.83**

The average LEC value for each investment type mentioned above is 8.39, 10.78 and 14.83 US Cents/kWh respectively. The two provinces with the largest number of projects (Binh Thuan and Ninh Thuan) are very close to the overall average. The highest LEC is observed in Bac Lieu which hosts the operational semi-offshore project Cong Ly that carries the highest installation costs in the portfolio and a low capacity factor. The province Binh Dinh has the lowest LEC. This province holds two projects with low installation costs (around 1.9 million USD/MW) and capacity factors of 31% and 38%. Another province with a low LEC is Soc Trang, it hosts one project with very low OpEx

[16] Average capacity factor and LEC values by provinces as a function of three different values of the target project IRR; 6%, 10% and 16% respectively. The overall averages (last row) are taken across the portfolio and not the already aggregated province-specific averages.

cost and one with the second highest capacity factor. Interestingly, the province with the largest number of projects (Binh Thuan) has the lowest average capacity factor.

The lowest LEC are observed at Tuy Phong 2, which is a result of an extremely low capital expenditure. The second lowest value was found for Phuoc Hai (Ninh Thuan) and can be explained by a combination of the highest capacity factor in the portfolio and below average CapEx and OpEx cost.

LEC

Within this section, the LEC is calculated according to Equation 1 (see 4.2.3). Furthermore, the impact of the three key factors is analyzed and discussed.

For further analysis, it has to be acknowledged that six of the nine manufacturers are represented in Vietnam with only one turbine. This makes it difficult to separate turbine specific properties from other factors, which possibly have an influence on the LEC. The turbine specific LEC values range from 8.74 to 12.74 US Cents/kWh. The lowest LEC are achieved by United Power (China), Wind Force and Enercon; while the highest value is achieved by IMPSA and Vestas. However, because of the poor statistics it is hard to separate specific factors related to manufacturers from other factors that are linked to the project. The remaining four manufacturers are close to the average LEC value, in particular Fuhrländer, which is supplying turbines for 10 projects. Apart from Fuhrländer, the remaining turbine manufacturers are General Electric (GE), Gamesa and Avantis.

i. Capital expenditures

The average CapEx is 2 million USD/MW. The number presents an “all-in” figure, including procurement costs for the components as well as costs specific to the Vietnamese market like network connection cost, special requirements due to climate conditions or costs for logistics like road construction. However, the total CapEx also include calculations of specific incentives like import tax exemptions. The effect of tax incentives and land lease exemptions on the FIT will be quantified in section 5.2.4.

Projects calculated on the basis of operating with GE turbines claim the highest installation costs of USD 2.26 million, closely followed by projects that envisage to use turbines from Vestas (USD 2.22 million) and Avantis (USD 2.10 million). From the four GE projects, three are the most expensive within the overall portfolio. Wind force presents the lowest cost of 1.88 million USD/MW and has one of the smallest turbines (900 kW) with lowest hub height (59 m) in the portfolio. The remaining manufactures range fairly close to the overall average (e.g. turbines from China (United Power) and Argentina (IMPSA) with 1.94 and 1.95 million USD/MW respectively).

Based on the data provided, the CapEx per MW installed range from 1.30 to 2.49 million USD/MW. The lowest value of 1.30 million USD/MW does not seem very plausible compared to the remaining projects and based on international experience. Interestingly, the project Tuy Phong 1, which is already in operation, claims a high cost factor of 2.42 million USD/MW.

ii. Operational expenditures

The average OpEx cost is 35,407 USD/MW and year. Like CapEx, it is an ‘all-in’ figure that includes all cost components specific to the Vietnamese market. The Project Tuy Phang 1 (in operation) has extreme high OpEx costs of over 78,000 USD/MW per annum. This is the highest value in the portfolio. It is more than double the average portfolio value and 40% above the second largest value. It is also much higher than the average OpEx cost of projects deploying Fuhrländer turbines (38,750 USD/MW).

For Tuy Phang 1, OpEx costs absorb almost 30% of the total electricity revenue. For the Cong Ly project, the second wind farm in operation, OpEx cost amount to 25,318 USD/MW per annum, which is much lower than the average OpEx cost. Interestingly, Cong Ly has a GE turbine, which has very low OpEx cost, but on the other hand the highest capital expenditure. However, the OpEx contract specifies a 3% indexation per year, which has a strong impact on the LEC. Overall the OpEx cost of the projects within the portfolio varies considerably. The two projects in operation represent extremes.

iii. Capacity factor and quality of site

To complete the analysis of the wind park portfolio, we investigate the relationship between the LEC and the capacity factor. The capacity factor is a measure, which combines the wind potential of an area with the efficiency of wind harvest and the quality of wind farm design. With this analysis we shed light on the question of suitability of capacity-factor-dependent tariffs.

Taking all projects into account, the average capacity factor of the project portfolio is 29.85%. Figure 15 displays the cumulative wind power capacity of the project portfolio as a function of the capacity factor. The results show that there is a potential of 458 MW of wind power projects with a capacity factor of 29.8% and higher. Up to a cumulative capacity of 856 MW, projects have a capacity factor of 25% and higher.

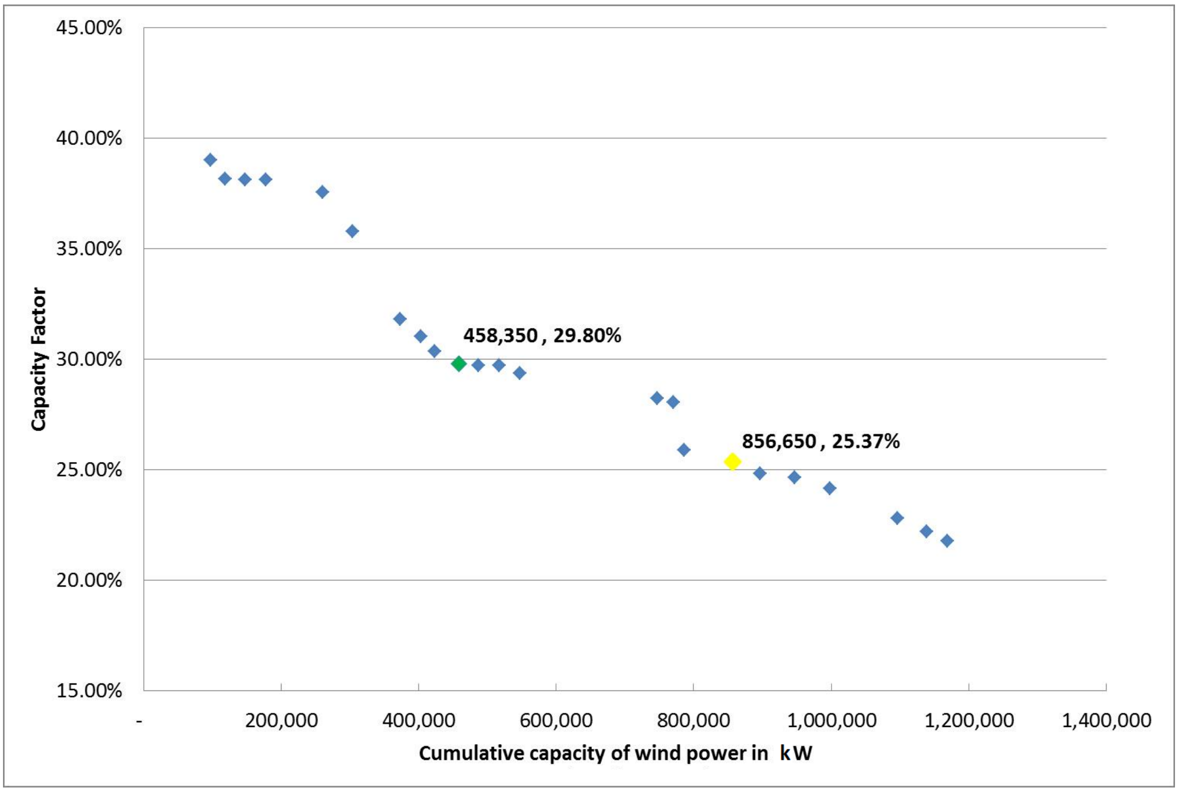


Figure 15: Cumulative wind power capacity as a function of capacity factor for the wind project portfolio with a combined total wind power capacity of 1,169 MW.

Analyzing the relation between the LEC and capacity factor, we find a high linear correlation of over 70% (cf. Figure 16).

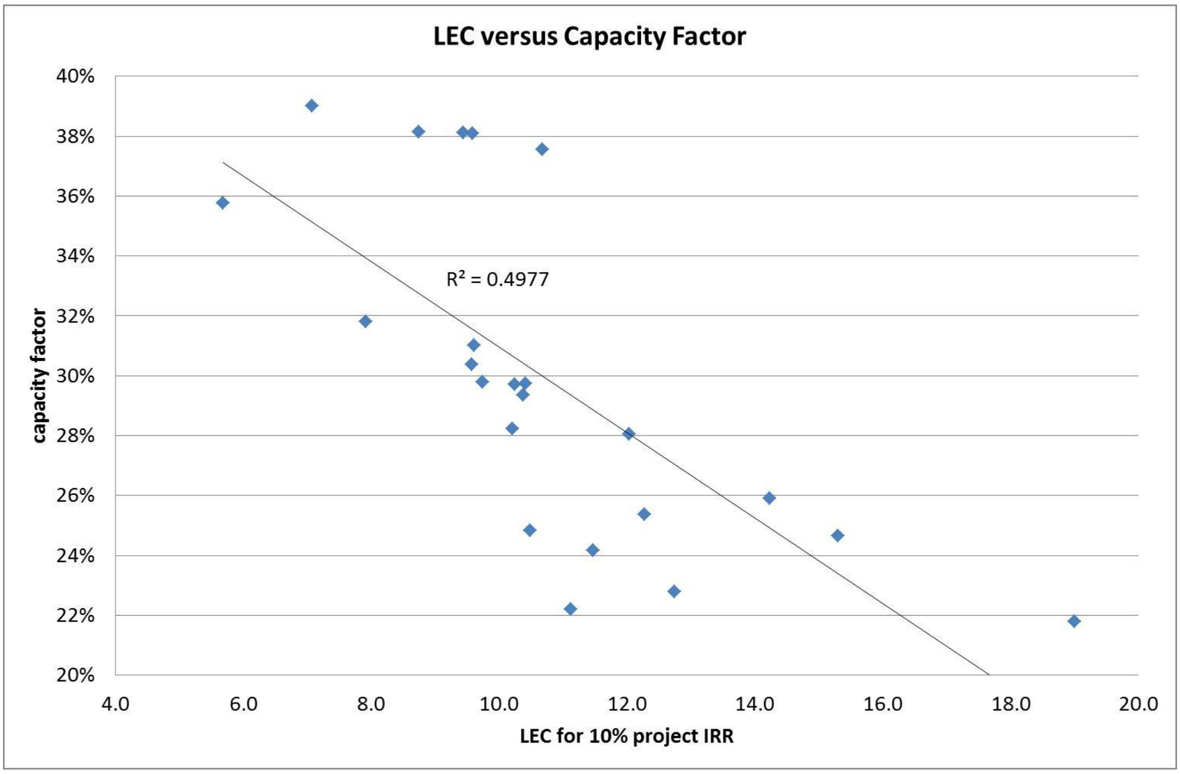


Figure 16: LEC versus capacity factor for the 23 different projects[17]

This is a very important result that underpins the importance of good wind conditions combined with appropriate wind farm design and layout.

4.2.5 Bankability of debt financing

In practice, financing decisions by debt investors are based on sound information underpinned by enforceable contracts such as cost for construction, equipment and OpEx including insurance etc. The study team's analysis (using FS/Q assessments) is mainly based on non-binding estimates. Based on the data provided by project developers, 18 out of the 23 projects are not bankable, i.e. they would not qualify for project finance. All of these 18 projects exhibit negative cash flows in at least one year of operation based on the expected energy projection (base case). The five remaining projects (An Phong, Phuoc Hai, Tran De, Tuy Phong 2, and Phuoc Huu) present – given the provided information – positive cash flows over the entire operation period. A closer look reveals that they all share a certain pattern with respect to relevant key factors. They exhibit a combination of at least two of the following four key assumptions:

- assumption of high FITs above 10 US Cents/kWh, which exceeds the current FIT
- low interest rates of less than 6%, which cannot be accessed via commercial lending
- high capacity factors of above 30%
- debt financing with 12 or more years maturity and no grace period.

It is questionable whether these assumptions are realistic. For the Tuy Phong 2 project for instance, the assumptions of capital expenditures are extremely low with approximately 1.3 million USD/MW.

It remains unclear whether the five projects mentioned above would qualify for project finance and meet *all* necessary conditions to pass a financial due diligence. Some of the input parameters of

[17] The regression line implies a linear correlation of about 70.5% between capacity factor and LEC.

the available data are questionable. Almost all projects – except those already in production – apply constant OpEx cost components without any escalation over time. However, typical OpEx contracts demand – after a two year guarantee period – an annual escalation that is either fixed (e.g., 3% p.a. like in Cong Ly) or linked to a reference index like the consumer price index (CPI). This is an important factor, greatly affecting LEC calculations and weakening the ability to repay the debt.

Debt investors require that a project stays solvent under adverse wind scenarios. Generally a P90 wind scenario must still provide a sufficient buffer to meet the debt service. For a P90 scenario, the annual electricity production adopted in the model must not be undercut with a probability of 90% in any given year of operation. Consequently, assumptions for the forecast electricity generation are comparatively conservative, considerably reducing the annual income of the project. Due to the lack of reliable information, the study team could not calculate the performance under a P90 scenario. However, when applying conservative estimates for the annual wind fluctuation based on experience (approx. fluctuation of 20%), only one project out of the 23 would meet the financial requirements under a P90 scenario.

To summarize the analysis of debt financing, we find that the main financing obstacles are high interest rates and short maturities of typically 10 years combined with a grace period of two to three years. This entails a very high debt service that is concentrated in a relatively short period of seven to eight years. During that period, up to 85% of the capital expenditure must be repaid. Even the more sound projects cannot shoulder such a high debt service. This is a major obstacle for wind power project development in Vietnam. Higher tariffs alone cannot cure this problem; complementary measures to ensure bankability of the proposed projects as well as easier access to debt financing need to be put in place.

4.2.6 Data quality and model risk

The analysis performed above relies heavily on the quality of the input data. Two aspects are relevant: How reliable is the data provided? How sensitive is the derived LEC with respect to variations of the input parameters? Both questions will be addressed in the following.

i. *Data quality*: The CapEx and OpEx cost components from FS/Q data are developers' estimates and should be based on pre-contract arrangements and price indications of component and service suppliers. If the project portfolio represents a good statistical sample of the overall market, it can be concluded that these numbers are fairly robust.

   The situation is different for the estimation of the annual electricity production. Banks generally demand up to three independent wind audits from renowned wind auditors to evaluate the financial viability of a wind farm project and the resulting debt financing conditions. Within wind resource assessment reports, auditors provide estimates of the average annual energy production and wind distribution at the wind farm site and outline uncertainties for a specific park layout and turbine type. For this assessment, wind measurements under standardized, well documented conditions are essential.

   The FS/Q data does not provide information on the quality and process of wind measurements and wind auditing. Attempts by the study team to gain more detailed insights on the quality of the wind data have been unsuccessful. Therefore the study has to rely on the data provided to the team and trust its integrity and soundness.

   Wind measurements currently undertaken by GIZ will most likely reduce the error margin substantially. However, a first analysis of GIZ wind data indicates that the average capacity factor of 30% derived from the FS/Q data is fairly optimistic. The GIZ wind measurement sites have been selected with the objective to provide a broad coverage of wind measurements in Vietnam, and not with the aim of identifying wind sites with the highest wind potential. Out of the total of ten GIZ wind measurement sites, six would not qualify for wind farm development.

ii. *Model risk*: Due to the uncertain model input parameters, it is very helpful to estimate the impact of changes of these parameters on the resulting LEC within a sensitivity analysis. Table 9 shows to what extent the input parameters can vary so that the LEC do not increase by more than 0.5 US Cents/kWh.

Table 9: Sensitivity analysis of LEC calculation for the three parameter CapEx, OpEx and Capacity factor

Sensitivity parameter	∆ LEC in US Cents/kWh
∆ CapEx +0.112 Mio. US/MW	0.50
∆ OpEx +12,100 US/MW p.a.	0.50
∆ Capacity factor -1.38%	0.50

An increase in CapEx by 0.112 million US/MW, in OpEx by 12,100 US/MW p.a or a reduction of the capacity factor by 1.38% would each result in an increase of LEC of 0.5 US Cents/kWh. Inversely, a decrease of CapEx of about 0.112 Mio US/MW could compensate for a poorer wind location with a 1.38% lower capacity factor. The analysis thus serves as an important gauge to set changes in costs in relation to the capacity factor. The analysis shows that the sensitivity of the capacity factor is the most critical as the fairly small change of 1.38% already causes an increase of LEC of 0.5 US Cents/kWh.

5 Proposal for the re-design of the support mechanism and framework

5.1 Summary and overview

In this section, the study develops proposals for a FIT for onshore wind projects that results in a reasonable project IRR for investors[18]. It explores whether respective tariff options could attract debt financing by assuming different interest rate levels. Furthermore, the annual amount in million USD is calculated that is required to subsidize a tariff increase on the basis of the electric buying price of 6.8 US Cents/kWh paid by EVN[19]. A sensitivity analysis with adverse and favorable wind and cost scenarios complements this analysis.

The most important result is:

A project IRR of 10% for onshore projects requires a FIT of 10.4 US Cents/kWh[20].

A project IRR of 10% for nearshore projects requires a FIT of 11.2 US Cents/kWh[21]

The estimated FIT level is very similar to the results derived by FICHTNER in a wind study carried out for Vietnam in 2009 (Fichtner, 2009). Although a completely different data base was used in the FICHTNER study[22], the average LEC value of 10.5 US Cents/kWh under good wind conditions shows striking resemblance with the results presented in this current study of the IoE/GIZ team.

At a constant FIT of 10.4 US Cents/kWh for onshore, and a FIT of 11.2 US Cents/kWh for nearshore projects, for the period of 2015-2030, the target installation of 1 GW wind power – if covered by an 80/20 ratio on- or nearshore projects – would require additional subsidy payments amounting to an average annual amount of USD 68.8 million from 2015 to 2030, under conservative assumptions (see Chapter 0 below). A peak would be reached in year 2027 with USD 112.7 million, declining sharply thereafter.

With the two feed-in tariffs, typical projects would qualify for debt financing – even under the considered adverse scenarios – if loans at an interest rate of 6% could be secured. Moving from 10 years maturity to 16 years maturity should make the project even more attractive to debt and equity investors if such a condition is accepted by debt investors. While debt investors should benefit from a higher minimum Debt Service Cover Ratio (DSCR), which is the ratio of cash available each year for debt servicing, equity investors would profit from a higher equity IRR.

Loans at 10% interest rate still result in bankable projects, however, for adverse cost and wind scenarios this could result in financial stress.

In the remainder of this section the study calculates the implicit effect of tax incentives like reduced corporate tax and exemptions from import tax on the FITs. It then concludes the section with a short discussion of how a market development would look like and give remarks on alternative tariff structures.

[18] Calculations for near- and offshore projects can be found in the long version of this study.
[19] Note: as mentioned above, due to limited funds, VEPF will most likely not be in the position to pay the additional "state support electric price" of 1.0 US Cents/kWh to future wind power project developers.
[20] The tariff is considered to be an "all-in" figure without any further support like VEPF mentioned above.
[21] It should be noted that the data for the onshore calculations is stronger than for nearshore calculations.
[22] The different methodology applied by FICHTNER was due to the fact that, at the time of their study, no pre-/feasibility data sets where available. As a result, more of a "top down approach" was applied by FICHTNER, while this current study was able to use a set of available pre-/feasibility data.

5.2 Proposed FIT adjustments

The basis of this section is a calculation of a required FIT derived from LEC calculations for different cost and capacity factors of the wind farm. The study team considers three different investment types, which have already been introduced in the previous section (see 4.2.4).

In this section, the impact of FIT adjustments on the financial viability of wind power projects is being explored. In order to evaluate the effectiveness of FIT adjustments, the study team performed the following four steps:

Step 1: Evaluation of the tariff based on LEC estimation for the three different investment types introduced above. The evaluation distinguishes between a base case scenario and three adverse as well as three favorable scenarios (see Table 10 below). In the different scenarios, wind potentials and cost levels are varied.

Step 2: Analysis of different debt financing options. That means exploring whether highly subsidized, strategic and commercial debt financing allow for financially viable projects. The analysis of FS and Q data revealed that debt financing and financing conditions are a major barrier; step 2 is therefore of particular importance.

Step 3: Quantification of the effect of tax breaks on the overall performance. Additional support mechanisms like a reduced corporate tax for renewable energy projects and exemption from import tax for RE equipment contribute positively to the required FIT level. The section below explores the net contribution to the FIT of the two current tax incentive schemes.

Step 4: Description of a likely path of wind power development till 2020 based on the above insights and quantification of the required FIT subsidies and debt volume over time.

Further explanation to step 1: General approach to derive a range of FIT levels
The basis of this analysis is to explore the different FIT levels that deliver a required project IRR as a function of wind farm parameters. The following factors were modelled in this step:

(i) CapEx expressed in million USD per MW capacity installed. This number is considered as an ‘all-in’ number and includes all additional cost factors specific to the Vietnamese market.

(ii) OpEx per year expressed in TUSD per MW installed. This figure refers to OpEx in the first year of operation; OpEx cost factors are exposed to different indexations as a function of years in operation. Like CapEx, this is an “all-in” figure.

(iii) Capacity factor in %. The capacity factor is a measure of the quality of a wind site and the design of the wind farm.

These three factors are the relevant factors in the calculation of the LEC as previously defined in Equation 1. They form the basis of the FIT calculations. As a reference, the study team assumes a base case for each of the three factors. In addition, the team derives two scenarios for each factor by applying a single positive and a single negative change to each factor. As a result, a set of seven scenarios is obtained (cf. Table 10 below). The parameterization of the different scenarios is derived from the FS/Q data and cross validated with international data. The LEC calculated is the pre-tax LEC. The pretax LEC was chosen as a benchmark in order to be independent of actual tax levels implied in the simulation. The impact of tax effects is calculated in a separate step.

5.2.1 FIT calculation for onshore projects

Scenario set definition and LEC estimation

The following scenario set is applied:

Table 10: Scenario set for wind farm projects at an onshore location[23]

Scenario	CapEx [million USD/MW]	OpEx [T USD/MW*year]	Capacity Factor
Base case	**2.00**	**35.00**	**30.0%**
CapEx+	**2.25**	35.00	30.0%
CapEx-	**1.65**	35.00	30.0%
OpEx+	2.00	**45.00**	30.0%
OpEx-	2.00	**25.00**	30.0%
Capacity+	2.00	35.00	**35.0%**
Capacity-	2.00	35.00	**25.0%**

The figures for the base case scenario are derived by calculating the averages of the FS/Q data. The CapEx and OpEx of wind farm projects in Vietnam are slightly above the typical level in other countries. The CapEx and OpEx scenarios may represent different local regions and different technologies that results in higher or lower installation and maintenance costs due to more or less favorable conditions at the site, that affect the civil works and logistics, e.g. infrastructure such as roads or network connection. However, CapEx and OpEx are considered to be 'all-in' figures that capture all cost components.

The variation of the capacity factors reflects locations of different wind conditions. Table 11 summarizes the LEC values as a function of required project IRR and scenario. The period of operation is assumed to be 20 years.

Table 11: LEC values in US Cents/kWh at required project IRR of 6%, 10% and 16% for the scenario set at onshore locations[24]

Scenario	LEC 6%	LEC 10%	LEC 16%
Base case	8.12	10.39	14.25
CapEx+	8.95	11.51	15.85
CapEx-	6.96	8.83	12.00
OpEx+	8.54	10.80	14.65
OpEx-	7.70	9.98	13.84
Capacity+	6.96	8.91	12.21
Capacity-	9.74	12.47	17.10
Min. value	**6.96**	**8.83**	**12.00**
Base case	**8.12**	**10.39**	**14.25**
Max. value	**9.74**	**12.47**	**17.10**

[23] Besides the base case scenario two additional scenarios are derived for each of the factors CapEx, OpEx and capacity factor. Base case and variations of each factor are shown in bold.

[24] The last three lines show the minimum, base case and maximum value of LEC. The minimum value relates to a higher capacity factor and lower CapEx and the maximum value to a lower capacity factor

Please note that the minimum value of 6.96 US Cents/kWh at a project IRR of 6% lies below the current official support level of 7.8 US Cents/kWh. At a project IRR of 10%, the required tariff ranges from 8.83 to 12.47 US Cents/kWh with a **value for the base case scenario of 10.4 US Cents/kWh.**

5.2.2 Requirements and feasibility of acquiring debt funding for wind financing

This sub-section is dedicated to step 2 of the evaluation scheme, i.e. the analysis of different debt financing options. The evaluation of the FS and Q studies revealed that debt financing its conditions is a major obstacle for successful wind farm development. Consequently, the analysis of debt financing is of central importance.

In step 1, the study explored which tariffs are required to secure a certain project IRR to investors of wind farms projects. In general, such projects are not only financed with equity, but also rely on the availability of debt financing. In the FS and Q, debt financing is widely used with debt levels ranging from 85% to 70% of total capital requirements. The average equity level is approximately 25%[25]. Interest rate levels range from below 2% up to 12% with an average of 6.3%.

In the following, the study explores the impact of different interest levels and maturities of the loan on the financial viability of a project from the perspective of debt and equity investors. The key performance figure for debt investors is the minimum DSCR observed over the debt financing period. As mentioned above, the DSCR is the ratio between the annual cash flow available for distribution and the fraction available for debt servicing. The min. DSCR value must not fall below 1.0 – otherwise the debt service cannot be covered. Banks generally demand a minimum DSCR in the range of 1.1-1.2 under adverse scenarios. The key equity performance measure is the after-tax equity IRR.

Three different interest rate levels, i.e. 2%, 6% and 10%, relating to the three investment types described in section 4.2.4 are considered. Interest rates of about 2% may be provided by international financing institutions / donors banks (e.g. World Bank, ADB, and KfW). Debt investments with an effective rate of 6% may be achieved by balance sheet financing, internal loan transfer pricing or a mixture of different loans, including highly subsidized loans and commercial loans. An interest of 10% relates to competitive rates of commercial loans for project finance. In the simulation, debt financing is assumed to be denominated in USD, similarly to the equity financing and the majority of CapEx. The revenues are paid in VND but refer to a certain FIT in USD. Thus the income and debt service are linked to the same currency and do not impose exchange rate risks. Commercial investors may have to rely on local debt funding denominated in VND. The FS/Q data shows that interest rates for debt financing are at a level of up to 12% in Vietnam. The interest rate level of 10% (maximum interest rate level scenario) thus lies slightly below local funding conditions. However, the FIT is exposed to USD inflation, which may be advantageous as FIT revenues appreciate against the VND. It is therefore conservative to substitute debt funding denominated in VND at an interest rate well above 10% by an effective loan denominated in USD at 10% interest rate.

In general, debt financing is exposed to lower risk than the respective equity investment. An equity investor therefore expects an IRR on equity that is larger than the interest rates of the respective debt financing. Table 12 illustrates useful combinations of debt interest rates and project IRR with respect to the base case scenario for the three different investor types demanding 6%, 10% and 16% project IRR respectively.

[25] By international standards, this equity level is relatively low. An equity-debt ratio of 30/70 is a prevailing approach.

Table 12: Useful combinations of debt financing and required project IRR[26]

Project IRR / Debt Rates	6%	10%	16%
2%	YES	YES	YES
6%	NO	YES	YES
10%	NO	NO	YES

Debt investments with an effective interest rate of 6% may be achieved by balance sheet financing, internal cross subsidy of a loan or a mixture of different loans including highly subsidized loans and commercial loans. For example, a 50/50 mix of a subsidized loan of 2% and a commercial loan of 10% results in an effective interest rate of 6%. The financial viability for debt and equity investors is evaluated by calculating the min. DSCR and the equity IRR for each pair of project IRR and interest rate. Loan maturity is assumed to be 10 years and the equity ratio is kept at a constant value of 30%.

Results

Table 13 below summarizes the results for the after-tax equity IRR and min. DSCR for commercial funding at 6% interest rate for different tariffs that provide a target project IRR of 6%, 10% and 16% respectively. Equity IRRs are shown as after-tax figures. Reduced tax rates for renewable energy projects are assumed. Project IRRs at 6% do not seem to be rational from an equity investor's point of view as the debt investor would have a higher return at a lower level of risk. In the following section, the study considers a constellation where debt interest is higher than equity IRR as "not financially viable". However, the different calculations are still carried out in order to complete the analysis.

Color scheme of the following table: The different colors of the numbers represent the different configurations depicted in Table 12 and respectively transferred to Table 13 (green: both financially viable and bankable, red: not bankable and black: bankable but not financially viable). Bankability is defined by a min. DSCR of more than 1.0.

The simulation results for loans with a maturity of 10 years with interest rates of 6% (strategic lending) are summarized. Calculations for 10% (commercial lending) and 2% (highly subsidized lending) and for maturities of 16 years are shown in the full version of this report only.

Table 13 depicts the after-tax equity IRR and min. DSCR for different tariffs that provide a target project IRR of 6%, 10% and 16% respectively. With the current maximum remuneration of 7.8 US Cents/kWh (electric buying price of 6.8 US Cents/kWh by EVN and state support electric price of 1.0 US Cents/kWh by VEPF) for project developers, only two scenarios would result in bankable projects.

[26] From the nine combinations of debt rates and project IRRs that are possible from a theoretical point of view, only six are financially viable as equity investors expect a higher return than debt investors. The categorization is based on the base case scenario.

Table 13: Key performance figures for debt (min. DSCR) and after-tax equity (equity IRR) for strategic loans at 6% interest rates and 10 years maturity for different tariffs that provide a target project IRR of 6%, 10% and 16% on the base case scenario.

Tariff & key figure	Current tariff 6.80 + 1.0 US Cents / kWh		LEC(6%) 8.12 US Cents / kWh		LEC(10%) 10.39 US Cents / kWh		LEC(16%) 14.25 US Cents / kWh	
Scenario	Min. DSCR	Eq. IRR	Min. DSCR	Eq. IRR	Min. DSCR	Eq. IRR	Min. DSCR	Eq. IRR
Base case	0.87	3.61%	0.91	4.67%	1.21	12.29%	1.69	26.12%
CapEx+	0.77	1.26%	0.81	2.22%	1.09	8.93%	1.52	20.78%
CapEx-	1.05	8.09%	1.35	13.00%	1.45	18.90%	2.03	37.04%
OpEx+	0.81	2.17%	0.85	3.25%	1.16	10.91%	1.64	24.64%
OpEx-	0.93	5.01%	0.97	6.07%	1.27	13.67%	1.75	27.61%
Capacity+	1.05	7.94%	1.10	9.19%	1.43	18.27%	1.99	35.55%
Capacity-	0.69	-0.80%	0.73	0.12%	0.99	6.46%	1.40	17.40%

This shows clearly that even for the most optimistic case of financial support to the tune of 7.8 US Cents/kWh, project developers cannot implement financially viable projects. Instead, we find that a tariff of 10.39 US Cents/kWh that delivers a pre-tax project IRR of 10% could result in a financially viable project if strategic debt financing of 6% interest rate can be secured.

5.2.3 Sensitivity of financing conditions

Obtaining debt financing and servicing the loan in the operational period is critical to successful wind power development in Vietnam. Table 14 below shows the simulation results of various debt financing conditions on the after tax equity IRR and the minimum DSCR. The underlying base case scenario is a tariff of 10.4 US Cents/kWh for 20 years, an equity ratio of 30%, a loan maturity of 10 years, interest rates of 6% and the loan redemption type 'annuity'. In the following the impact of each factor is discussed in more detail.

Table 14: The impact of debt financing conditions on after-tax project IRR and minimum DSCR (first two columns) and the absolute changes with respect to the base case scenario (third and fourth column).

Scenario	Equity IRR	DSCR min	∆ Equity IRR	∆ DSCR min
Base Case	12.29%	1.21	-	-
Equity 20%	13.39%	1.06	1.10%	-0.15
Maturity +1Y	12.74%	1.18	0.44%	-0.03
Grace period +1Y	12.73%	1.12	0.43%	-0.09
Interest rate +1%	11.37%	1.16	-0.92%	-0.05
Linear redemption	11.91%	1.07	-0.38%	-0.14

As a general result, all modifications to the loan conditions deteriorate the DSCR compared to the base case:

i. *Reduced equity ratio*: Increased leverage due to a reduced equity ratio increases the after tax equity IRR but substantially lowering the minimum DSCR close to default (compare third row). Banks will most likely not accept such low value in the base case. However, it has been argued by project developers that a high leverage in the range of 25%-15% equity ratio is required to realize wind power projects. This could be achieved by either finding additional equity investors that provide equity funding or theoretically increase the FIT to increase the DSCR and thus improve the credit quality. A tariff increase by a further 1.5 US Cents/kWh to 11.9 US Cents/kWh would offset the fall in the DSCR due to a reduced equity ratio (results not shown). Simultaneously, it raises the after-tax equity IRR above 20%, which is possibly hard to communicate to electricity customers and the tax payer.

ii. *Change of maturity of the loan*: An extension of the loan period by one year increases the equity IRR due to higher free cash flow during the repayment of the loan.

iii. An *introduction of a grace period* has a similar effect on the equity IRR as an extension of the loan maturity. A grace period may help a project in the beginning of the operation phase and improves the equity IRR but it deteriorates the conditions for the debt investor. The DSCR is reduced significantly because the repayment period is shortened.

iv. *Increase of interest rate*: An increase of debt interest rate reduces the equity IRR and the DSCR due to a higher debt service and lower distribution payments.

v. A *change in the redemption scheme* from annuity to linear is a disadvantage to equity and debt investors (compare last row).

5.2.4 Impact of tax effects and land lease exemptions on FIT

Two tax incentive schemes that are applicable to wind farm developments make investments more attractive than other business ventures. Reductions in corporate tax and exemptions from import taxes have a positive impact on project and equity IRR. In this sub-section the study translates tax incentives into an equivalent FIT component.

a) Reduced corporate tax

The standard corporate tax rate in Vietnam is 22% (as of 01/01/2014). It will be reduced to 20% as of 01/01/2016. A wind farm project company enjoys a reduced corporate tax to the following extend: exemption from corporate tax in the first four years of operation and a 50% tax break for the following nine years. Assuming that a wind farm will start operation in 2016, we benchmark the tax incentives against a flat rate of 20% corporate tax. To explore the impact of corporate tax breaks the following question arises: “How does a reduced corporate tax scheme for wind farm subsidize the FiT in US Cent terms”. In order to answer this question the standard corporate tax conditions are applied and an increased FiT is calculated that delivers the same project IRR as in a reduced corporate tax environment. The onshore base case scenario is taken as a reference and the break-even FIT difference is calculated in order to obtain the same project IRR for the two different tax schemes.

Table 15: Break even FIT adjustment to obtain the same project IRR in standard versus reduced corporate tax scheme.

Tariff	LEC (10%): 10.4 US Cents/kWh	LEC (16%): 14.25 US Cents/kWh
Break even FIT	0.3 US Cents/kWh	1.0 US Cents/kWh

Overall the effect is fairly small. In a lower return environment (LEC at 10% project IRR) the effect is only 0.3 cents. The depreciation in the first 10 years substantially reduces the taxable income.

The tax reduction during this period therefore does not make a significant difference. From year 15 the regular tax applies. The impact of tax reduction is therefore limited to a five year period only.

In a high return environment the effect is larger and accounts for 1 US Cent difference in the FIT. For this scenario, the taxable income in the first 10 years is larger and tax incentives have a higher impact on the effective FIT.

In any case, it needs to be kept in mind that tax incentives have a limited impact on the project IRR. In a situation of financial stress, tax incentives cannot cushion liquidity problems as there are no deductible tax payments due to the financial losses incurred.

b) Exception from import tax

The approach is similar to the one above: A calculation of the required FIT increase to compensate for an increase of CapEx due to various import tax levels. The tax is applied to 80% of CapEx which is the approximate share of equipment cost.

Table 16: Break even FIT adjustment to obtain the same project IRR for different import tax levels as compared to an import tax exemption.

Tariff/Break even FIT	LEC (10%): 10.4 US Cents/kWh	LEC (16%): 14.25 US Cents/kWh
+10% import tax	0.7 US Cents/kWh	1.0 US Cents/kWh
+15% import tax	1.1 US Cents/kWh	1.5 US Cents/kWh
+20% import tax	1.4 US Cents/kWh	2.1 US Cents/kWh
+25% import tax	1.8 US Cents/kWh	2.6 US Cents/kWh

For a tariff of 10.4 US Cents/kWh, the effect on the FIT is about 0.7 US Cents/kWh for each 10% import tax applied; for an assumed tariff of 14.25 US Cents/kWh, an increase in tax by 10% leads to a potential decrease of the FIT of approximately 1 US Cent/kWh. At a tax level of 25%, the total benefit is 1.8 US Cents/kWh or 2.6 US Cents/kWh for a tariff of 10.4 or 14.25 US Cents/kWh respectively.

c) Waiving of land lease cost

CapEx and OpEx cost derived from FS/Q data do not include any land purchase or lease cost as the land is provided free of charge as part of the current licensing agreement. However, the purchase or lease payments are typically a relevant cost component. Hence, exemption from these costs represents an indirect subsidy that may be translated into an equivalent FIT component. In order to quantify the net effect of lease exemption, the study team calculates the LEC at 10% pre-tax project IRR for typical annual lease costs in the range of 5% of annual electricity revenues. In the analysis, the indexation of lease cost is ignored as electricity revenues are already denominated in USD. A potential depreciation of the VND against the USD would be compensated by USD linked lease payments. The simulation shows that lease payment exemption accounts for a corresponding FIT component of 0.5 US Cents/kWh. The sensitivity is 0.1 US Cents/kWh for each 1% revenue linked lease payment.

5.2.5 Simulation of a pathway and strategy to reach installation goals of PDP VII

In order to reach the target installation of 1 GW wind power, the simplest approach is the assumption of a linear growth over the next six years in the period from 2015-2020 with an installation rate of 167 MW per year. Table 17 summarizes the relevant key figures of the analysis.

In this short version of the study, an implementation of the target installation with onshore and nearshore wind farms is assumed.

As indicated earlier, in order to install 1 GW, a total investment amount of ca. USD 2.0 billion is required. If an average debt-equity ratio of 70/30 is assumed, the total equity required is USD 600 million and the total debt is USD 1.4 billion (see Table 17).

In the following, it is assumed that the market is developing in three phases linked to the three investor types introduced in section 4.2.4. In this simple approach, the market share for each investment type is one third but the timing of market entry is different for each investment type. It first starts with highly subsidized investments which are characterized by the lowest entry barriers. This phase is assumed to start in 2015 and end in 2018. It is followed by strategic investments starting in 2016 with a peak investment in 2017. Commercial investors would enter the market in 2017. The investment volume is assumed to grow continuously until 2020.

Table 17: Key investment figures for wind farm development assuming a linear growth towards the goal of 1 GW installation over six years from 2015 to 2020.The total cost of installation as well as equity and debt amounts are listed as a total sum(column two) and per year (column three).

Key Figure\Value	Total Target (1GW)	Per year
Installation in MW	1,000	167
CapEx in million USD	2,000	333.33
Equity in million USD	600	100
Debt in million USD	1,400	233.33

How the market could start

The above outlined market entry scenario implies a total debt volume of USD 467 million and an equity volume of USD 200 million in each investment type segment. This amount appears to be reasonable given the pool of donors, e.g. KfW, WB, EIB, and USAID. Similarly, the group of strategic investors could include turbine manufacturers, large industry enterprises, and sovereign wealth and pension funds. They could be assumed to be large enough to provide the required funding. The last group of investors includes funds and infrastructure funds that operate globally, in the Asia pacific region or domestic. For this group, the segment of infrastructure debt funds could be a promising source for debt funding.

Riding the learning curve and future FIT adjustments

Our base case scenario assumes an average capacity factor of 30%. From an economic point of view, the best wind locations will be developed first. This means that the early developments may possess above-average capacity factors. Figure 15 above showed that on the basis of the 23 reference projects there is a potential of 458 MW of wind power projects with a capacity factor of 29.8% and above. This accounts for almost 50% of the target installation until 2020. Installation beyond this amount may have under-average capacity factors. The effect of a below average wind site may be compensated by more cost-efficient construction and operation due to local capacity building up over time and scaling effects with respect to logistics and manufacturing which can rely on experience from the first “phase” of project development (i.e. the projects with a capacity factor higher than 29.8%). As a result, the improvement on the cost side may compensate potential shortcomings due to inferior wind locations. Consequently, investors could rely on equal profitability even if wind conditions are less favorable.

FIT levels for wind power can be adjusted as markets mature. This is due to the scaling effects described above for both investment cost as well as for the ongoing operations and maintenance cost. Cost reduction due to "learning effects" may be feasible if a critical mass of installation, e.g. 500 MW, is completed and a track record of at least 3-5 years operational experience is built up. However, should government decide to review the FIT level for new wind farm projects in the future, sufficient leeway and advance notice should be given to project developers, equity and debt investors in order to provide planning reliability.

In order to show the effects of a potential future FIT adjustment, a scenario analysis has been performed to derive market conditions that would justify a tariff reduction of 1 US Cent/kWh to then 9.4 US Cents/kWh for onshore projects at a pre-tax project IRR of 10% under the base case scenario. A reduction of CapEx to 1.65 million USD/MW (base case 2.0 million USD/MW), OpEx of 20,000 USD/MW p.a. (base case 35,000 USD/MW p.a.) would justify a tariff reduction by 1 US Cent/kWh even if capacity factors will drop to 26.1% (base case 30%). Table 18 shows potential combinations of key factors that would allow a FIT reduction by 1 US Cent/kWh.

Table 18: Combinations of CapEx, OpEx and capacity factors that result in a LEC of 9.4 US Cents/kWh for onshore projects at a pre-tax project IRR of 10%.

CapEx in Mio. USD/MW	OpEx in USD/MW p.a.	Capacity factor in %
1.85	20,000	29.0
1.75	30,000	28.9
1.75	25,000	28.3
1.65	30,000	27.5
1.65	25,000	26.8
1.65	20,000	26.1

However, it is emphasized here that this analysis is merely of theoretical nature and based on assumptions about cost development over time. Political decision-makers should not rush to new FIT adjustments, but rather carefully monitor market development, "learning effects" and cost development before any further adjustments are made in order to avoid further uncertainties for market stakeholders.

5.3 Framework adjustment

There is a strong need for an independent central management body that can coordinate the actions to promote wind power development in Vietnam. This includes both road-mapping / strategy development for wind power planning and the regulation of licenses as well as financing and tax supports. In the past, these important coordinating functions have been disaggregated among different organizations and authorities. An illustrative example is that currently there are different wind power projects, namely onshore, nearshore (national grid-connected) and off-grid (Phu Quy island). Still, there is only one decision No. 37/QD-TTg dated 29/06/2011, which is being applied to all the three different types of wind power projects. Although there was a temporary adjustment of electricity prices for nearshore wind power projects, it is recommended to have different tariffs for different project types[27].

If the new FITs are accepted (as calculated and proposed above) the current regulations and processes concerning wind power should be adjusted accordingly. The framework adjustments will

[27] The information was collected during a meeting with VEPF.

include two areas: i) regulations; and ii) processes. The following section summarizes the comments and recommendations for the necessary adjustments.

5.3.1 Regulations

With regard to Decision No.1208 general propositions for wind power development include:

- The Government encourages wind power projects to develop on a commercial and sustainable basis.
- The Government encourages all domestic enterprises of all ownerships, international enterprises and international organizations to participate in the development of wind power.
- The Government supports grid-connected wind power projects with production costs equal or below the introduced FIT.
- The provision of investment licenses and grid-connection services shall be in accordance with the regulations of Government on investment project management.
- Electricity generated from qualified grid-connected wind power producers will be purchased by the distribution companies under the introduced FIT.
- Qualified wind power producers will benefit from the non-negotiable standardized power purchase agreement published by MoIT.

Below the main adjustments for existing regulations are discussed.

Considering the current Decision No. 37, additional articles should be adjusted and supplemented as follows:

- Article 14 of chapter 3 "Support of the electricity price for grid-connected wind power projects": This Article should be re-designed to meet both types of wind power projects – onshore and nearshore. This article should state clearly that the nearshore wind power projects should take up only a certain defined percentage of the total installed wind power capacity within each development stage. The reason for this are the higher costs of nearshore wind power projects compared to onshore. Initially, the Government should focus on the development of wind power projects at sites with reasonable costs.

- One additional article "Financing funded supports for wind power" should be added after Article 14 of Decision No. 37. This new Article should clarify the financing sources for support and establish rules to control the financing sources as well as the levy on the electricity price for customers. MoIT will develop details for this new Article and submit it to the Government for consideration and approval.

After the adjustment of Decision No. 37 has been carried out, the related Circulars issued by MoIT should be changed accordingly. The following adjustments are recommended:

- Revision of the Circular No. 96/2012/TT-BCT dated 08/06/2012 on guiding financial support mechanism for grid-connected wind power projects. Revision of the Circular 31/2011/TT-BCT dated 19/08/2011 on adjusting electricity sales prices according to basic input parameters: i) exchange rates ii) fuel prices and iii) structure of the energy sector. The electricity sales price is computed and examined monthly, based on fluctuations of basic input parameters. These parameters should be considered regarding the fund to support wind power projects. It is recommended to add one more parameter which is the electricity output from wind power to the national grid (this calculation method is already applied in China and many other countries). Under current regulations, if the average generation costs increase by more than 5% of the current electricity sales price due to fluctuations of the three basic input parameters (ΔG ≥5%GHH), Vietnam Electricity will factor the electricity production and business costs not yet fully accounted for into the electricity sales price. The price may, however, not be increased by more than 5%. It is recommended to extract one part of the budget from the increase of the electricity sales price and reallocate it to the funding of wind power projects. For this purpose, the electricity output from wind energy projects could be included as a 4th parameter to be considered. As a consequence of the introduction of the 4^{th} parameter, the total sensitivity of the three above-mentioned parameters is expected to decrease. The financial support of the wind power projects will not reduce EVN's profit, but will rather be reallocated to electricity consumers.

- In addition, a number of circulars related regulations on electricity prices and annual implementation guidelines should be adjusted for additional synchronization.

5.3.2 Processes

One of the main reasons for the delay in issuing licenses (including investment, construction, grid connection licenses), which leads to a prolonged implementation time of the projects, are poorly conceived administrative procedures and regulations by authorities. The biggest barriers appear within the period of implementation and publication of the wind power planning at the provincial and national levels. Lack of planning causes many additional procedures for the wind power investors, such as applying for the project request to be added to the provincial power planning, negotiating connection points, etc.

Provincial authorities require a comprehensive wind power planning on provincial as well as national level. These documents play an important role and could help considerably in shortening the duration of the license issuance.

The following examples could help to better understand the situation:

- At present, only two provinces (Ninh Thuan and Binh Thuan) have provincial wind power development plans until 2020 with a vision up to 2030. Some other provinces are as well developing projects and/ or are waiting for approval. In order to conduct the provincial wind power planning, the provinces have to acquire reliable wind data and enough fund, which constitutes a challenge for many provinces. For this reason a number of wind power projects exist, but are not yet included in the provincial wind power planning. In order to be accepted and added into the wind power planning, the investors have to comply and implement different complex and complicated procedures (according to point 5 of Article 4 in Circular 32 /2012/TT-BCT).

  To overcome these complications, the completion of the National Wind Power Master Plan is essential. The National Wind Master Plan would not only support investors to select to right sites for wind measurements, but also reduce risks as well as save time for investors/ developers while getting different permission papers.

- The procedure for grid-connection is regulated in Article 3 of Circular 32/2010/TT-BCT (for power plants connected to the medium-voltage and 110 kV grid) and in Article 3 of Circular 12/2010/TT-BCT (for plants connected to 220kV). It applies to partners selling electricity to the grid, but does not specify any special priority for electricity generated by wind power plants.

Connection of wind power plants to the national grid is regulated in article 7 of Decision 37/2011/QĐ-TTg. Wind power plants will use the priority regime on exploitation of all power and electricity output generation conforming with zone wind regime of the wind plant (regulation in point 4, article 7 of Decision 37/2011/QĐ-TTg).

In order to improve the licensing procedure, the following adjustments are recommended:

Table 19: Proposal for the adjustment of processes

Procedure and current status	Proposed adjustments	
	Processing time and documents (for government institutions)	**Quality of the submitted document (for investors)**
Agreement on site selection (36 days)	10 – 15 days.	Quality of submitted documents must be improved
Agreement on inclusion to the power development plan (30 days)	- GDE will approve this document 20 days after receiving the full eligible documents. - National or provincial wind power development plans should be updated timely.	Quality of the submitted documents must meet requirements.
Procedure on issuing investment license	- Required time for survey and investment project setting: 12 months. - Issuance of document on grid connection point: 15 days - Issuance of investment license: 30 days	Quality of the submitted documents to authorities must be improved.
Development of the project investment report		Quality of the documentation for project investment report and construction design must be improved.

6 Financing the proposed FIT

6.1 Rationale for government support

There is a global trend towards the liberalization of the power sector, i.e. reducing the influence of the Government, promoting private sector involvement in order to replace vertically integrated state-owned monopolies and introducing efficient market mechanisms. Vietnam follows this strategy with the implementation of a competitive electricity market.

Having said this, international experience has shown that without adequate governmental support, it is difficult to bring renewable energy technologies to a stage where they are cost-competitive with conventional generation technologies. A transition period is needed, where markets are developed, and costs are thereby driven down to the level of average electricity production costs in the whole system.

As the following analysis and calculations will point out, wind power is already close to average electricity generation costs. The current cost gap between wind power generation and average electricity generation is expected to close, if government actively supports the kick-starting of the wind market with an appropriate support mechanism, until it has reached a point where up-scaling is possible without additional subsidies. In fact, after a certain stage of market development is reached, it is expected that wind power might even contribute to a decrease of average electricity production costs[28].

Against this background, it is important that government support is rendered to trigger wind market development, thereby bringing down costs to a competitive level, and making wind power a least-cost option for the Vietnamese energy mix.

The Vietnamese Power Development Plan VII has already set wind power development targets for the years 2020 and 2030:

- In 2020: 1,000MW of wind power will have been installed, corresponding to 0.7% of total national electricity generation of 330 billion kWh.
- In 2030: 6,200MW of wind power will have been installed, corresponding to 2.4% of total national electricity generation of 695 billion kWh.

6.2 Funding requirements to develop the on- and nearshore wind market

The following section outlines the total funding requirements needed to reach the short-term target of a 0.7% wind energy share of the total national electricity generation in 2020, and a 2.4% share of wind energy in 2030, respectively, with on- as well as nearshore application, assuming an incremental capacity installation over the 16 year period. The costs indicated below represent the total additional costs of wind-generated electricity with respect to the average electricity production costs in the whole system, which are assumed to increase over time. Based on available project data, the future wind portfolio in Vietnam is assumed to consist of 80% onshore and 20% nearshore wind power projects.

The total funding requirements are dependent on the feed-in tariff applied. The FITs for onshore and nearshore generation, as outlined above, would be profitable for projects expecting an internal rate of return (IRR) of 10% at 10.4 US Cents/kWh, and 11.2 US Cents/kWh, respectively. Two

[28] Currently, neither avoided external costs of conventional power production (e.g. CO2 emissions), nor direct environmental and social advantages of renewable power are reflected in the prices set by the competitive electricity market. If these were incorporated in the wholesale electricity price, renewable power generation would already now, without support mechanisms, have the potential to compete with conventional power generation.

scenarios have been developed and are shown in the tables in sections **Error! Reference source not found.** and 6.3.2.

1. The first scenario applies a **constant FIT of 10.4 US Cents/kWh** from 2015-2030 for onshore wind power projects (80%), and a **constant feed-in tariff of 11.2 US Cents/kWh** for nearshore wind power projects (20%) in the same period.

2. The second scenario applies the same FITs for on- and nearshore projects (80/20 share) until the year 2020. From 2021-2030, a **reduced feed-in tariff of 9.4 US Cents/kWh for onshore** and a **reduced feed-in tariff of 10.2 US Cents/kWh for nearshore** projects is applied[29].

Funding requirements for scenario 1 (constant FITs until 2030) would affect total electricity production costs with additional annual costs of USD 5.0 million in 2015, USD 40.6 million in 2020, and USD 93.4 million in 2030. Annual funding requirements would peak in 2027 with approximately USD 112.7 million and then decrease over time towards the year 2030 (cf. section 6.3.1).

Funding requirements for scenario 2 (reduced FITs as of 2021) would affect total electricity production costs with the same amounts in 2015 (USD 5.0 million) and 2020 (USD 40.6 million), as the same tariffs apply until 2020. After peaking in 2022 (with USD 43 million), the annual additional funding requirements decrease and amount to USD 29.1 million in 2025. As of 2028, the installed wind capacity even subsidizes the system, contributing positively with an amount of USD 50.3 million to the reduction of the overall average electricity production costs in 2030 (cf. section 6.3.2).

There are various options and instruments, by which funding costs can be met. Internationally, experience has so far been best with tariff-funded support mechanisms and tax-funded support mechanisms. In case of the tariff-funded support, the off-taker purchases electricity from the wind park operator directly; EVN would thus remunerate operators. The additional costs for wind-generated electricity compared to electricity from conventional sources could be financed by a levy on the electricity price. In case the tax-funded approach is applied, the state budget is used directly for the payments. The following sections discuss the two options.

6.3 Tariff funded support for constant and reduced FIT

For the tariff-funded option, a levy[30] is applied to each unit of electricity consumed, in order to meet the funding requirements.

The calculations for the levy are based on the following assumptions:

- The share of wind energy in the national electricity generation is 0.7% in 2020 and 2.4% in 2030, in line with the Government's power development targets outlined in Decision No. 1208/QD-TTg – PDP VII.
- The electricity demand in 2020 and 2030 is based on the assumptions made in the officially approved PDP VII (see chapter 6.1 above).
- The average electricity production costs are assumed to be rising from current levels of 7.7 US Cents/kWh to 8.8 US Cents/kWh in 2020, and ca. 10 US Cents/kWh in 2030[31].

[29] This „reduced FIT" scenario is based on the assumption that considerable learning and scaling effects will possibly allow for a reduction of 1.0 US Cent/kWh of both FITs as of 2021, once a certain maturity of the wind power market has been reached. The study team assumes that such maturity is achieved when Target 1 of the PDP VII (i.e. 1 GW of installed capacity by 2020) has been realized.

[30] The payments can be arranged as items in the electricity bill of customers (i.e. similar to the water bill applicable for waste water) or allocated to the overall costs of the power system. As mentioned above, the Circular No. 31/2011/TT-BCT dated 19 Aug. 2011 should be enhanced by one parameter. An assessment of this electricity surcharge/levy mechanism is however beyond the scope of this study.

- The levy rate is defined as the difference between the proposed FIT and the average electricity production costs (reference tariff).
- The share of wind energy produced onshore is 80%, the share of nearshore is 20%.

As mentioned above, two scenarios for applying a levy to the electricity price are presented hereafter[32]:

- a constant FIT for onshore of 10.4 US Cents/kWh and for nearshore of 11.2 US Cents/kWh until 2030 (section **Error! Reference source not found.**);
- a reduced FIT after the first GW has been installed, assuming that the learning and scale effects have allowed to bring down CapEx and OpEx (section 6.3.2).

6.3.1 Constant FITs at 10.4 US Cents/kWh for onshore and 11.2 US Cents/kWh for nearshore from 2015 to 2030

Table 20 below highlights the funding requirements for a constant FIT of 10.4 US Cents/kWh from 2015 to 2030 for onshore and a constant FIT of 11.2 US Cents/kWh for nearshore projects, assuming the generation from wind power outlined in rows 3.1-3.4. These costs (depicted in row 8) would be distributed to consumers in the form of a levy rate per kWh of electricity sold (see row 12).

On average, the electricity price would **increase by VND 3.5/kWh** in the period from 2015-2030. In 2015, the levy on each kWh produced in the entire electricity system amounts to an additional VND 0.6/kWh, increasing to VND 2.9/kWh in 2020. A peak is reached in 2023 and 2024 at VND 5.3/kWh. From 2024 to 2030, however, the levy falls to VND 3.2/kWh, due to rising average electricity production costs in the whole system, resulting in decreasing incremental costs for the two FITs.

With marginal effects on the electricity price in the first years, a relatively small peak of the levy of VND 5.3/kWh in 2023/24, and decreasing effects thereafter, it can thus be concluded that a promotion scheme for wind energy through the proposed FITs of 10.4 US Cents/kWh and 11.2 US Cents/kWh will not only result in the desired development of wind power projects in Vietnam, but also have **positive effects on the average electricity production costs** in the medium to long-term.

[31] Source of data and information used in making assumptions for and calculation of average selling electricity price of the power system in period 2013 - 2020, with vision to 2030, is taken from current regulations of the Government and the Ministry of Industry and Trade on average electricity tariffs in period 2013-2015.
[32] More details of the calculation and additional scenarios are shown in the full version of this report.

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
(1) - PDP VII original version (GWh)	194,303	218,798	244,334	271,151	299,449	329,410	358,393	388,770	420,674	454,244	489,621	526,355	565,112	606,048	649,328	695,148
(2) - Share of wind electricity (PDP VII original version)	0.09%	0.15%	0.25%	0.40%	0.55%	0.70%	1.18%	1.43%	1.78%	1.92%	2.07%	2.18%	2.32%	2.37%	2.39%	2.40%
(3) - Electricity production from wind energy (GWh)	175	328	611	1,085	1,647	2,306	4,215	5,547	7,475	8,740	10,120	11,500	13,110	14,344	15,491	16,684
(3.1) Elec Generation (onshore), 80%	140	263	489	868	1,318	1,845	1,845	1,845	1,845	1,845	1,845	1,845	1,845	1,845	1,845	1,845
(3.2) Elec Generation (nearshore), 20%	35	66	122	217	329	461	461	461	461	461	461	461	461	461	461	461
(3.3) Elec Generation (onshore), 2021, 80%							1,527	2,593	4,135	5,147	6,251	7,355	8,643	9,630	10,548	11,502
(3.4) Elec Generation (nearshore), 2021, 20%							382	648	1,034	1,287	1,563	1,839	2,161	2,408	2,637	2,876
(5.1) - FIT 1 (onshore) USDCent/kWh	**10.4**	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
(5.2) - FIT 1 (nearshore) USDCent/kWh	**11.2**	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
(5.3) - FIT 2 (onshore as of 2021), USDCent/kWh							**10.4**	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
(5.4) - FIT 2 (nearshore as of 2021), USDm							**11.2**	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
(6) – Increasing avg. electricity production costs, USDCent/kWh	7.7	7.8	7.9	8.2	8.5	8.8	9.1	9.2	9.3	9.4	9.5	9.6	9.7	9.8	9.9	10
(7) - Incremental cost: FIT 1, USDCent/kWh	2.9	2.8	2.7	2.4	2.1	1.8	1.5	1.4	1.3	1.2	1.1	1.0	0.9	0.8	0.7	0.6
(7.1) - Incremental cost: FIT 2, USDCent/kWh							1.5	1.4	1.3	1.2	1.1	1.0	0.9	0.8	0.7	0.6
(8.1) - Cost of funding FIT 1, USDm	5.0	9.1	16.2	25.6	33.9	40.6	33.7	31.4	29.1	26.7	24.4	22.1	19.8	17.5	15.2	12.9
(8.2) - Cost of funding FIT 2, USDm							27.9	44.1	65.1	74.6	82.8	88.3	92.9	91.5	87.0	80.5
(8) - **Total funding cost USDm**	5.0	9.1	16.2	25.6	33.9	40.6	61.5	75.4	94.2	101.4	107.3	110.4	112.7	109.0	102.2	93.4
(12) - **Levy in VND/kWh**	0.6	1.0	1.6	2.3	2.7	2.9	4.1	4.6	5.3	5.3	5.2	5.0	4.7	4.2	3.7	3.2

Table 20: Funding costs onshore and nearshore (80/20 share) with constant FIT, assuming increasing average electricity production costs

6.3.2 Reduced FITs as of 2021 to 9.4 US Cents/kWh for onshore and 10.2 US Cents/kWh for nearshore

Assuming that the FIT scheme is successfully implemented until 2020 and the desired wind power capacity of 1 GW has been installed, a reduction of the FIT level could be considered in order to price in expected reductions in CapEx and OpEx as a result of increased market capacities and learning effects. In the scenario below, the reduction of the FIT to a provisionally anticipated level of 9.4 US Cents/kWh[33] for onshore, and 10.2 US Cents/kWh for nearshore commences in 2021 in order to alleviate the cost burden for the customer, while maintaining a stable investment environment (constant project IRR).

This adaptation of the FIT, however, is critically dependent on the factor that a large number of installations has taken place; the study team recommends the 1 GW margin, after which considerable experience should have been gathered by project developers, certain infrastructure will be available in the country (e.g. cranes), and capacities have been developed. In addition, it seems likely that the first GW will first and foremost focus on those wind sites with the best capacity factors. Table 21 below shows the results for a scenario, where the FIT is being reduced by 1 USCent/kWh after considerable experience has been gathered in the market.

In this scenario, for the period of 2015-2020 the results are the same as for the scenario with constant FITs (the same FITs of 10.4 US Cents/kWh for onshore and 11.2 US Cents/kWh for nearshore apply). As of 2021, reduced FITs of 9.4 US Cents/kWh for onshore, and 10.2 US Cents/kWh reduce the levy. As of 2028 wind power installations potentially contribute to a decrease of average electricity production costs, i.e. ceteris paribus overall electricity production costs are "subsidized" by wind power.

It should be noted again that these effects are estimates and critically depend on the stage of market development prior to reducing the feed-in tariffs for onshore and nearshore wind power.

[33] As already mentioned in Chapter 5, a scenario analysis has been performed to derive market conditions that would justify a tariff reduction of 1 USCent/kWh to 9.4 USCents/kWh for onshore, and 10.2 US Cents/kWh for nearshore, respectively.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
(1) - PDP VII original version (GWh)	194,303	218,798	244,334	271,151	299,449	329,410	358,393	388,770	420,674	454,244	489,621	526,355	565,112	606,048	649,328	695,148
(2) - Share of wind electricity (PDP VII original version)	0.09%	0.15%	0.25%	0.40%	0.55%	0.70%	1.18%	1.43%	1.78%	1.92%	2.07%	2.18%	2.32%	2.37%	2.39%	2.40%
(3) - Electricity production from wind energy (GWh)	175	328	611	1,085	1,647	2,306	4,215	5,547	7,475	8,740	10,120	11,500	13,110	14,344	15,491	16,684
(3.1) Elec Generation (onshore), 80%	140	263	489	868	1,318	1,845	1,845	1,845	1,845	1,845	1,845	1,845	1,845	1,845	1,845	1,845
(3.2) Elec Generation (nearshore), 20%	35	66	122	217	329	461	461	461	461	461	461	461	461	461	461	461
(3.3) Elec Generation (onshore), 2021, 80%							1,527	2,593	4,135	5,147	6,251	7,355	8,643	9,630	10,548	11,502
(3.4) Elec Generation (nearshore), 2021, 20%							382	648	1,034	1,287	1,563	1,839	2,161	2,408	2,637	2,876
(5.1) - FIT 1 (onshore) USDCent/kWh	**10.4**	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
(5.2) - FIT 1 (nearshore) USDCent/kWh	**11.2**	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
(5.3) - FIT 2 reduced (onshore as of 2021), USDCent/kWh							**9.4**	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
(5.4) - FIT 2 reduced (nearshore as of 2021), USDm							**10.2**	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
(6) – Increasing avg. electricity production costs, USDCent/kWh	7.7	7.8	7.9	8.2	8.5	8.8	9.1	9.2	9.3	9.4	9.5	9.6	9.7	9.8	9.9	10
(7) - Incremental cost: FIT 1, USDCent/kWh	2.9	2.8	2.7	2.4	2.1	1.8	1.5	1.4	1.3	1.2	1.1	1.0	0.9	0.8	0.7	0.6
(7.1) - Incremental cost: FIT 2, USDCent/kWh							0.5	0.4	0.3	0.2	0.1	0.0	-0.1	-0.2	-0.3	-0.4
(8.1) - Cost of funding FIT 1, USDm	5.0	9.1	16.2	25.6	33.9	40.6	33.7	31.4	29.1	26.7	24.4	22.1	19.8	17.5	15.2	12.9
(8.2) - Cost of funding FIT 2, USDm							8.8	11.7	13.4	10.3	4.7	-3.7	-15.1	-28.9	-44.8	-63.3
(8) - **Total funding cost USDm**	5.0	9.1	16.2	25.6	33.9	40.6	42.4	43.0	42.5	37.0	29.1	18.5	4.7	-11.4	-29.6	-50.3
(12) - **Levy in VND/kWh**	0.6	1.0	1.6	2.3	2.7	2.9	2.8	2.6	2.4	1.9	1.4	0.8	0.2	-0.4	-1.1	-1.7

Table 21: Funding costs onshore and nearshore (80/20 share) with reduced FIT as of 2021, assuming increasing average electricity production costs.

6.3.3 Interpretation of FIT calculations

The following charts illustrate the main results again. The total annual amount of USD required for funding (in blue) as well as the levy rates (in red) are depicted for constant **FITs of 10.4 US Cents/kWh for onshore, and 11.2 US Cents/kWh for nearshore, applied from 2015-2030**.

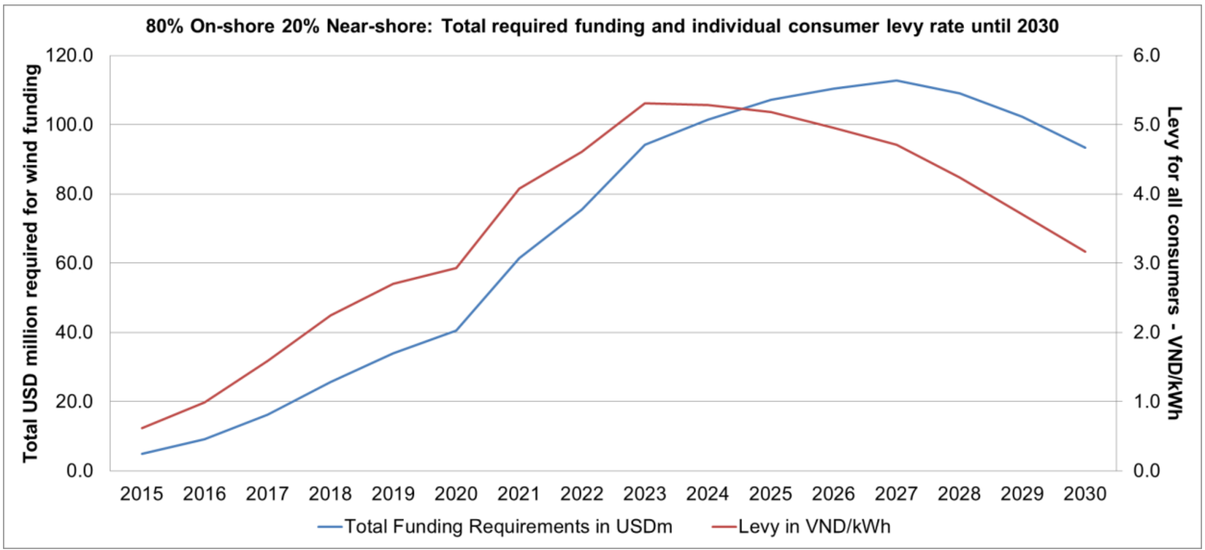


Figure 17: Total funding requirements and levy rate at constant FITs from 2015-2030.

Similarly, the chart below highlights the case with reduced FITs of 9.4 USCents/kWh for onshore, and 10.2 US Cents/kWh for nearshore as of 2021.

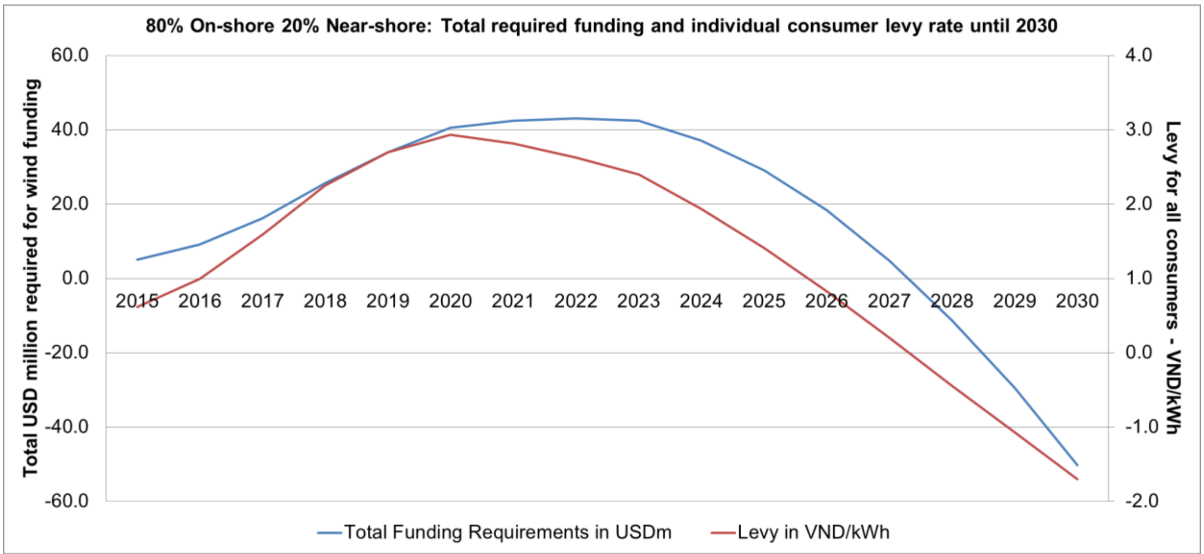


Figure 18: Total funding requirements and ley rate at reduced FITs of 9.4 US Cents/kWh for onshore, and 10.2 US Cents/kWh for nearshore from 2021-2030.

The results of both scenarios clearly show that, based on FITs of 10.4 US Cents/kWh for onshore, and 11.2 US Cents/kWh for nearshore, (and possibly a decrease to 9.4 US Cents/kWh and 10.2 US Cents/kWh respectively as of 2021), the **additional required funding amounts, and the respective levies** (that are added to the electricity price and allocated to the end-consumer) **for wind power development are marginal**.

For both cases, the **levy rate is very moderate with an average of VND 3.5/kWh over the period from 2015-2030** in the scenario with constant FITs (not exceeding 5.3 VND/kWh). At the same time, a **downward cost trend** can be observed in the near future.

For example, even in the years with the highest increase of VND 5.3/kWh (in 2023-2024), for households with a comparably high consumption of 200 kWh/month this would , result in a **marginal price increase of VND 1060 per month of the electricity bill**.

6.4 Tax-funded support

Another option, besides the financing of wind power development through cost reallocation to electricity prices and thus the end consumer, is a levy on the extraction, import and use of fossil fuels. Many countries have successfully established such a carbon tax support mechanism for the development of renewable energy in general and wind power in particular.

The application of the mechanism requires the calculation of external costs from burning fossil fuels, especially regarding the impact on the global environment from carbon emissions causing the greenhouse effect. The tax is based on carbon emissions but can also take into account acid rain gas emissions (NOx, SOx) as well as dust emissions from fossil fuel combustion (coal, oil, gas). The amount of free emission rates is set by the Government depending on the respective Government objectives. For the purposes of this study, it was assumed that the funding mechanism is based on two parameters: i) Greenhouse gas (GHG) emissions (carbon tax); and ii) Surcharge on the existing natural resource tax.

6.4.1 Greenhouse gas (GHG) emission tax (or carbon tax)

Under the Business as Usual Scenario[34], Vietnam's emissions are expected to increase dramatically by 2030. Vietnam's overall emissions will increase fivefold, per capita emissions fourfold, and per GDP by 20% between 2010 and 2030. These increases are projected to be driven primarily by the growth in the use of fossil fuel (mainly coal) for power generation. The share of coal in the power generation mix is expected to triple from 17% in 2010 to 58% in 2030 and is expected to account for two thirds of the increase in Vietnam's overall GHG emissions in that period.

[34] The BAU Scenario in this study has been constructed to be consistent with different sector and economic plans approved by the Government. For instance, the Power Sector BAU is in line with the Power Development Plan VII.

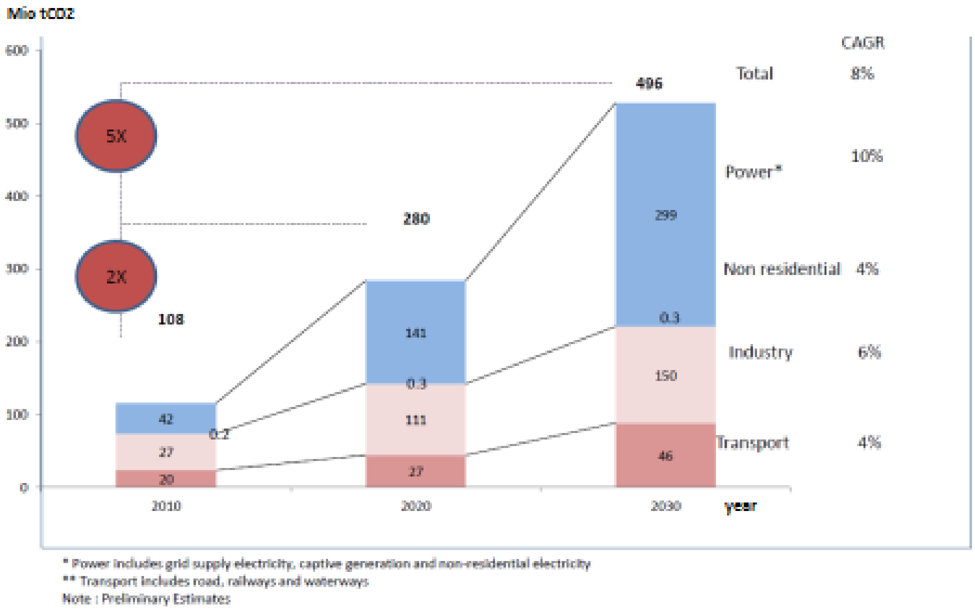


Figure 19: GHG emissions under the business as usual scenario (million tCO2)

This funding option could levy taxes based on a GHG emissions coefficient for each type of energy (petroleum products, coal, and gas). This option is already applied in other countries in South-East Asia, such as Thailand[35].

With an assumed tax of 1 USD/t CO_2, and taking into account the predicted carbon emissions for the Vietnamese power sector depicted in the figure above, the funding from carbon taxes could amount to USD 140 million in 2020 and 496 million in 2030.

6.4.2 Surcharge on the existing natural resource tax

Cross-subsidies from industrial consumer groups could be taken into consideration, e.g. by way of a surcharge on the natural resource tax.

The table below shows the tax rate which has been applied to different types of natural resources related to fossil energy.

[35] Thailand established a support fund for renewable energy and energy conservation. Regarding the income of the fund, next to the state budget, fees of imported fossil fuels are a main income source. Thailand applies a fee of 4 US Cents/liter on imported gasoline.

Table 22: Frame rate by law and tax rate by decision of National Assembly

No.	Types of the natural resources related to fossil energy	**Tax rate [%]** Tax Law 45/2009/QH12	**Tax rate [%]** By Decision of National Assembly	
I	**Coal**			
1	Coal (anthracite) - Mining belowground	4-20	7	
2	Coal (anthracite) - Mining open	6-20	9	
3	Lignite and fat coal	6-20	9	
4	Other coal	4-20	7	
II	**Crude oil** (Exploitation levels)	6-40		
	≤20.000 barrels/day		7	10
	>20.000 to 50.000 barrels/day		9	12
	>50.000 to 75.000 barrels/day		11	14
	>75.000 to 100.000 barrels/day		13	19
	>100.000 to 150.000 barrels/day		18	24
	>150.000 barrels/day		23	29
III	**Natural gas**			
	≤5 million m^3/day		1	2
	> 5 to 10 million m^3/day		3	5
	> 10 million m^3/day		6	10

However, such surcharge complicates the electricity tariff structure and will be difficult to implement as a respective adjustment requires the approval by the National Assembly of Vietnam to the modification of the current law. Therefore, the study team does not recommend this funding option for the wind power development in Vietnam.

Comparing the two options for support mechanisms (Tariff vs. Tax funded), we come to the following conclusions: The calculations for a tariff funded support mechanism in section **Error! Reference source not found.**[36] showed that for a FIT of 10.4 US Cents/kWh[37], only moderate increases of a levy on the electricity price are required in order to fund the targets of wind power development stipulated in PDP VII, i.e. a share of generation by wind power plants in total electricity output of 0.7% by 2020 and 2.4% by 2030. In addition, the adjustment of affected Circulars does not require amendments of existing laws or promulgation of new laws.

Against this background, the study team strongly **recommends to implement a tariff funded support mechanism** as opposed to a potentially more complex tax funded system.

[36] Different options: i). Electricity demand according to original PDP VII; and ii). Electricity demand according to revised PDP VI (draft) for period 2015 - 2030.
[37] In the long version of the study sensitivity analysis of this basic tariff were performed for tariffs of 9.4 US Cents/kWh and 11.4 US Cents/kWh.

7 Outlook / proposed steps for further integration of vRE into national grid

As has been shown above, a support mechanism, including FITs of 10.4 US Cents/kWh for onshore and 11.2 US Cents/kWh for nearshore wind power would be expected to contribute substantially to wind power market development in Vietnam. However, a support mechanism alone will not guarantee that wind power deployment will develop according to plan. In addition to the proposed FIT, regulation and administrative procedures need to be streamlined in order to develop wind power at the lowest possible cost. A strategy for the implementation of the FIT mechanism should be put into place that provides clarity on all administrative processes, and establishes a transparent and effective monitoring system, enabling government to take measures on the technical (system) level, as well as financially, should they become necessary.

On a technical level, the integration of RE technologies into the wider electricity system needs careful attention. Appropriate planning methods and cutting-edge tools allow for improved approaches and macroeconomic net benefits of renewable energy technologies (wind, PV, hydro, and biomass), thereby maximizing their **value to the power system**. RE technologies can be analyzed with regard to their interaction with the overall national generation mix and transmission system, so as to allow for an optimal expansion of RE technologies in time and space.[38] The newly available tools for system optimization would help answer the following questions, typical for variable RE technologies:

- **Energy Security:** What contributions can vRE make towards national energy security?
- **System reliability:** What is the “safety cap” for the national transmission system and for safe, worry-free dispatch? What is the “safety cap” for each region and grid node?
- **Distribution over time:** Which would be the optimal timing and share of different renewable options to install over time in Vietnam: wind, solar, biomass, geothermal, new hydro, etc.?
- **Distribution over space:** In which node of the national grid should which share of which technology be injected? What is the technical limit of the current transmission system? Can certain nodes be strengthened by injecting vRE? Which part of the transmission system would justify rehabilitation for more output?
- **Winners and Losers:** Who will benefit from (faster, slower) vRE scale-up and who will pay for it? Can the government redistribute benefits or reduce costs via specific, pragmatic policy measures?

GIZ and the study team stand ready to assist with such a more comprehensive and long-term planning process. However, in order to make best use of the tools outlined in the above list, the study team would require the following data inputs:

Table 23: Data Inputs

	What?	How?
1	Power plant List (latest existing; plus plan for next 5-10 years)	All power plants / units under operation: Min/Max Capacity, Unit Costs, startup costs, hydro generation by month. If available, hourly wind measurements >50m
2	Linearized National Grid (DC bus)	All substations and lines > 110 kVA or detailed national grid plan with specifics of each line and substation
3	Demand Curves (historical)	Typical average demand curve for each month or season (weekday vs. weekend) or daily values for an entire year for each substation

[38] The GIZ Viet Nam Energy Support Programme can assist in providing the necessary analysis.

In addition, in the short-term, the study team recommends that the Vietnamese Government introduces a transparent rule to **avoid "hot spots"** already during the initial 1 GW Wind Target Phase. Total capacity of wind projects feeding into the same transmission line should never exceed technically and economically reasonable levels, as recommended in [IEA 2014]. We suggest doing so by setting a simple capacity "safety cap" for each 110 kVA substation, with a "first come first served" rule applied for the total 1 GW. More precisely, licenses should only be granted up to this cumulative cap and linked to a time-bound completion guarantee by project sponsors, which should be backed by a bank guarantee. Licenses would be withdrawn in case of non-completion, if said non-completion can be attributed to the project sponsor.

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