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RE-COST

Study on Cost and Business Comparisons of Renewable vs. Non-renewable Technologies

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PART 1

1. EXECUTIVE SUMMARY

A host of policies and regulations govern the behavior of the electricity sector and significantly impact the decisions of producers, consumers, investors and other stakeholders. To efficiently steer norms and regulations, policy makers need accurate and up-to-date information on the factors that influence the decision making processes of investors in electricity generation. However, there are gaps in the data and information in the public realm with regards to the evolving economics of RET (Renewable Energy Technologies), especially when compared to those of non-RET. The objective of this report is to provide data, information, and insights to policy makers and to other actors in the electricity sector to help them assess the impact of policies in the business case of electricity generation.

Methodology and Scope - This report is based on the RE-COST Study, sponsored by IEA-RETD[1] in 2012-2013. The study documents, quantifies and analyzes the key factors that influence and determine the business case of new plants and projects; defining as such, power generating units with commissioning date between 2009 and 2013.

RE-COST focuses on seven countries: Canada, France, Germany, Japan, Norway, Sweden and Spain. Canada has been assessed through the analysis of three provinces: Alberta, Ontario, and Quebec. The technologies in the scope of the study include: on-shore wind – farms larger than 5 MW; off-shore wind – including operating plants, and development projects; solar PV – farms larger than 1 MW[2]; gas-fired plants – with emphasis on combined cycle generation; and coal-fired generation – focusing on super-critical pulverized coal plants. Hydro generation has also been analyzed, albeit at a lower level of detail than the other technologies.

RE-COST uses a custom-built simulation model, designed to test the influence of a number of factors in the business case of RET and non-RET generation including; plant design, technology specifications, region/country characteristics, market structure, support policies and incentives, etc. The model is supported by a database containing detailed – and largely confidential – information from more than 120 new plants and projects. Data have been enriched with insights from more than 90 interviews with industry actors, and have been contrasted and completed with publicly available information. A total of more than 1,200 simulations have been carried out to assess the potential business cases of the region/technology pairs included in the scope of the study.

The methodology used has distinct advantages: the results can be referred to concrete plants, it allows the evaluation of both the revenue and the cost sides of the business case of generation, it makes it possible to assess the potential sensitivity of investors to changes in policies, and it provides a quantitative basis to insights and recommendations. This guarantees a hands-on, practical approach. However, the findings displayed in this report are valid only within the specific scope (region/technology pairs), and the time span of the study (2011-2012). Extrapolating the results from RE-COST to other regions, technologies, or market circumstances may not yield accurate results and may lead to erroneous conclusions.

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[1] IEA-RETD: The International Energy Agency's Implementing Agreement on Renewable Energy Technology Deployment.

[2] The analysis includes large solar PV installations only. The results and recommendations pertaining to this technology are not applicable to small-domestic and roof-top solar PV plants. Thermo solar generation is also excluded from the scope of the study.

The Business Case of Generation – Insights - The analysis of the business cases of generation across the region/technology pairs included in the scope of the RE-COST study shows that, at the present, new on-shore wind, off-shore wind, and large solar PV plants still require policy support to bridge the gap between generation costs and market prices of electricity. However, this state of affairs may change in the near future. Technology and market dynamics are driving down the costs of RET generation and are increasing the costs of non-RET generation. Before long, best in class on-shore wind and large solar PV plants should be able to provide attractive business cases to investors, without resorting to revenue incentives, in regions with high proportion of thermal generation[3].

A number of factors should be taken into account when defining and optimizing policies in the electricity generation sector:

1. - Policies and regulations significantly affect the business cases of RET and non-RET generation projects. Analysis show that the cumulative impact of support schemes and incentives may reduce the total costs of development and operation of an RET plant by up to 6-8%[4], with average cost reductions ~5%[5]. Price incentives – such as FIT, RPS, green certificates, etc. – may significantly increase the unit revenue (US$/MWh) of a wind or solar PV plant.

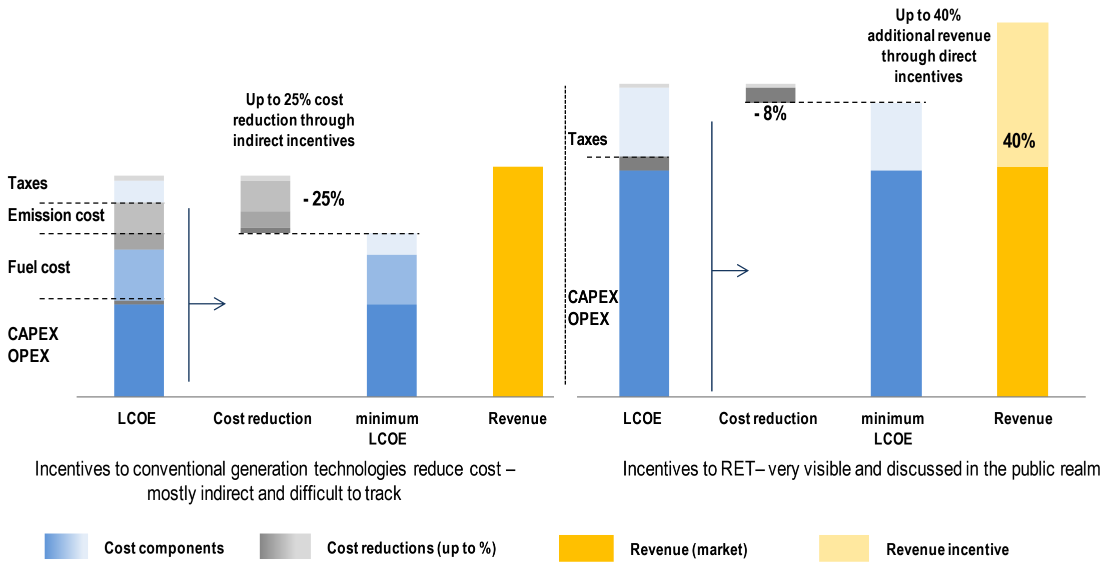

Figure 1. Sensitivity analysis - Comparisons between incentives to coal and on-shore wind (US$/MWh)[6]

But a frequently overlooked fact is that subsidies and regulations may also be a significant factor in the business case of non-renewable generation. Direct and indirect incentives for gas-fired and coal-fired[7]

[3] Regions where new, mature RET will need more time to become competitive include those with high proportion of hydro generation (Norway, Sweden, and Quebec), and regions with very low fuel prices (gas in Alberta).

[4] The result of simulating the cumulative impacts of grants of land, support to alleviate the cost of upgrading or connecting to the grid, and specific tax reductions that have been identified for some of the plants in the database.

[5] Represents an average of the impact of advantageous conditions obtained by the plants in the database of RE-COST.

[6] Direct incentives are fully visible, and are awarded to a generation technology. For instance feed-in-tariffs, green certificates, or auctions. Indirect incentives are less visible and affect the factor costs of generation. For instance, tax exemptions in the purchase of land of a plant, grandfathering of emissions, or provisions for local content.

[7] Examples of incentives to non-RET generation include grants of land to establish new plants, grandfathering of emission control requirements, subsidies to fuel (coal), public assumption of decommissioning costs, and tax reductions and exemptions. Section 3.10 of this report provides details about some of the mechanisms used to incentivize non-RET plants, and their approximate size.

plants may result in up to 10-25% reduction in generation costs. As a consequence, and as difficult as it might be, all incentives should be considered when assessing and comparing the costs of RET and non-RET generation[8].

2. - There is no unique cost of RET or non-RET generation. The ranges of costs associated to any generation technology are relatively large and highly dependent on the regulatory and market contexts. Best in class plants – those with high utilization rates, low capital costs, and low rates of financing – can have generation costs up to 50% lower than those of average plants [9]. This is especially relevant in the case of large solar PV, where large differences in costs can be observed when plants built several years apart and based on different technologies are compared. In addition, policies in different regions significantly affect generation costs by establishing an ample set of reward mechanisms, such as R&D grants, assumption by the TSO of the cost of connecting to the grid, tax breaks, reduction of administrative burdens, etc.

3.- The generation costs of new RET are gradually decreasing. On-shore wind generation is already competitive[10] in the regions evaluated by RE-COST. Intermittency issues aside, the costs of RET generation are declining, and approaching the costs of thermal generation (gas- and coal-fired plants), especially if the hidden subsidies that thermal generation plants may receive are not factored in. The rate of cost reduction is higher in large solar PV. Technology breakthroughs, the emergence of lower cost suppliers, and oversupply of components are resulting in a sharp reduction of the costs of this technology.

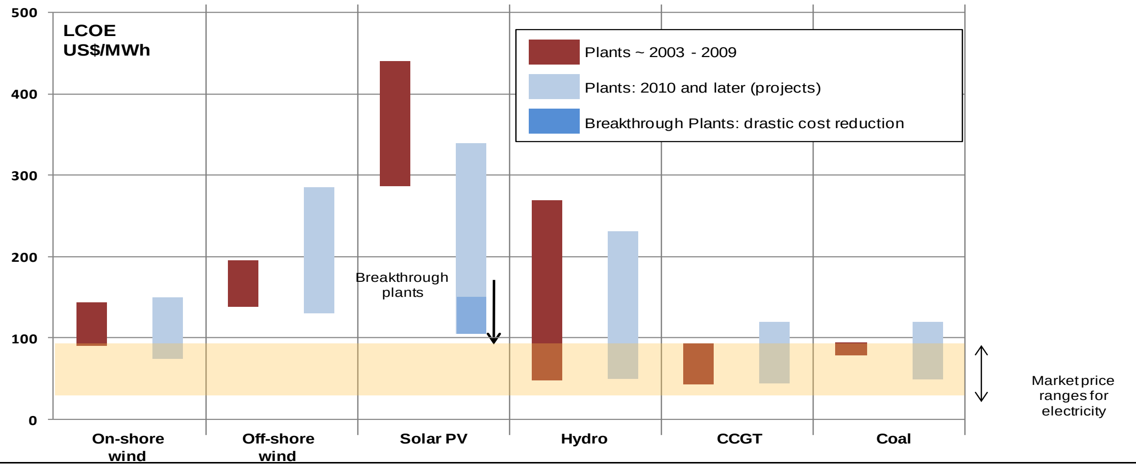

Figure 2. Evolution of generation costs – New plants and projects vs. older plants[11]

[8] A special effort has been made to identify and to separate the impact of policies on the costs and compensation to generation in order to present to the reader a clear view of the impact of technology evolution, market factors and policy decisions. However, in some cases in which policies act in an indirect way or are hidden, it has not been possible to segregate the effect of policies from that of other factors.

[9] The ranges of utilization, capital costs, and discount rates of a "best in class" plant depend on the region/technology. Specific ranges are provided in the main report for best in class and average plants in each region/technology pair evaluated.

[10] The term "competitive" used in the context of RE-COST refers to "costs of generation that are in the vicinity of market prices of electricity in the region/country being assessed".

[11] Cost displayed show LCOE (Levelized Costs of Electricity) obtained from simulations. The costs of investing in new grid, or connecting to the grid have been included as part of the capital costs of the plant. The average costs of transmission of each plant are not included in the ranges shown in the graph. The ranges of LCOE shown exclude the impact of direct incentives and support measures to plant costs. Indirect, hidden or not reported incentives may be included in some plants. Data from Japan have not been included to prevent bias (larger cost and revenue ranges)

This study does not aim to providing accurate forecasts of the potential costs of generation in the future. But the general belief emerging from industry interviews and expert reports is that most of the observed cost reductions in RET generation are structural and stable, and should persist in the short and mid-terms[12].

4.- The cost of generation of new non-RET plants (including gas- and coal-fired plants) are increasing, and might exceed the costs of generation of new RET plants in the near future in the regions in the scope of this report. Several factors contribute to this trend:

- **Lower utilization of thermal plants.** The average utilization of thermal plants in some countries has decreased in comparison with the utilization levels they reached in the past[13]. The market situation, and the competence with RET, which in some cases benefits from priority feed-in or from other incentives, are the main contributors to this outcome. In other words, policies that support RET plants have contributed to reduce the competitiveness of non-RET plants[14].

- **Higher capital costs of some new thermal plants.** Factors that contribute to increase the costs of capital of some new plants include: emission reduction systems, delays in construction and higher financing rates, driven in part by uncertainty about the future market and policy situations of some technologies (coal and nuclear).

- **Increasing costs of fuel** have been observed in some European countries and Japan[15]. However, fuel costs may significantly vary during the 40-70 years of the life of a thermal plant, changing the relative competitiveness of gas- and coal-fired generation vis-à-vis other technologies.

- **Emission compensation schemes may also be relevant. But their impact is somewhat reduced at the present.** The simulations conducted in the framework of this study consider emissions costs in the range of 0-10 US$/MWh. But in 2013 the average costs of emissions costs have dropped to circa 5 US$/MWh. The future competitiveness of thermal generation is going to be positively, or negatively influenced by the shape and provisions of future policies for control of emissions.

5.- The costs of both new RET and new non-RET generation are in general higher than the market prices of electricity in the regions in the scope of this study[16]. As a consequence, new generation plants require some kind of support to interest investors. In the case of new RET plants, the main form of support consist of visible and direct policy driven incentives. In the case of non-RET plants, support is

[12] Comparisons were made between the results from the database obtained in the framework of RE-COST (new plants) and data from publications (old plants). Breakthrough solar PV plants refer to plants with significant cost reductions observed during 2012 and expected in 2013.

[13] Average utilization in 2011 was 22% for CCGT plants in Spain, and 19% for coal-fired plants in France: well below the utilization level of up to 70-80% registered in the past

[14] It can be contended that, in general, the incentives given to a generation technology or plant decrease the relative competitiveness of any other competing technology or plant. Incentives to non-RET plants (for instance to gas and coal generation) may have also delayed the onset of RET generation.

[15] One exception to the previous observation is gas-fired generation in regions such as Alberta which benefits from prices of gas significantly lower than those of France, Germany, Spain and Japan. As a result, gas-fired plants operating in this region may display an LCOE of 15–25 US$/MWh lower than similar plants operating in regions where the prices of gas are at the levels defined by international markets.

[16] Market prices refer to the average compensations for the sale of electricity generated by these plants; including a range of prices determined by spot prices, OTC contracts, prices of electricity attributes, etc. Section 2.6.2 of the main report discusses the formation of electricity prices, and section 8.3 how prices have been assessed in this study.

also awarded, albeit in more indirect ways (providing CO_2 credits, supporting the coal industry, stimulating investment in gas infrastructure and exploration, etc.). Nowadays, new RET and non-RET plants find it difficult to compete in regions where the market prices of electricity remain low, driven in part by excess capacity, and also by an installed base that includes depreciated plants, or plants surpassing their economic lifetimes[17].

- **On-shore wind.** The LCOEs[18] of plants operating at or above relatively high capacity factors (25%) are approaching the market prices of electricity. For instance, some plants in France with costs ranging at ~75–80 US$/MWh, or in Germany with costs at ~70–80 US$/MWh are approaching the reference prices of electricity in these countries (64–75 US$/MWh in France, and 66–92 US$/MWh in Germany)[19].

- **Off-shore wind** plants display significantly higher costs than those of on-shore wind plants, largely due to the challenges associated to building and operating off-shore and to the deployment of new technologies. Ranges of costs of off-shore wind generation are: 155-325 US$/MWh in Japan, 145-210 US$/MWh in France, 155-375 US$/MWh in Germany, and 135-255 US$/MWh in Norway/Sweden.

- **Large solar PV plants.** Even the most technologically advanced farms still display generation costs significantly higher than the electricity market. Examples include Ontario, with 310-600[20] US$/MWh and France[21], with 180-300 US$/MWh. However, the situation is quickly changing. Some large solar PV plants included in the database – defined as breakthrough plants – display LCOEs in the range of 120 US$/MWh. These lower costs of generation are likely to become commonplace in the short and mid-terms

- At the present, **most new gas-fired and coal-fired plants are also likely to display costs of generation higher than the market prices of electricity.** Simulations result in LCOE ranges of 45-120 US$/MWh for gas-fired plants and 50-120 US$/MWh for coal-fired plants, higher than the reference compensation for generation (30-90 US$/MWh) in the countries in scope of RE-COST.

6. - The business case (BC) of electricity generation is highly dependent of the prevailing market and policy conditions. Therefore, plants with the same technology and similar operating conditions may have different business cases in different regions and countries. Figure 3 summarizes the results of simulations of the business cases of new plants across all the technologies in scope[22].

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[17] This statement refers only to new plants operating in 2011-2012 conditions. The gap between costs of RET generation and the market prices of electricity is significantly higher in countries/regions with generation based on intrinsically less expensive and largely depreciated plants. Examples include France (with 78% share of nuclear generation), Nordic Region (with 50% of hydro and 12% of nuclear generation), and Quebec (with 96% of hydro generation).

[18] LCOE: Levelized Cost of Electricity. LCOE ranges shown are the results of simulations with the RE-COST Model.

[19] Note that compensation for electricity includes a diverse set of prices paid for electricity: not only the spot price, but also the prices paid in bilateral contracts (OTC), and the compensation for services such as balancing, availability and others.

[20] These cost ranges do not reflect the costs of upcoming breakthrough plants observed in other countries in scope. It was not possible to acquire detailed information of solar PV plants in Ontario incorporating the latest cheapest modules.

[21] The data on the new solar PV auctions has not been included in this report. They were announced after the database of plants was compiled

[22] The table reflects the results of the business cases of new plants and projects with commissioning dates ~ 2010-2013, the electricity sector situation in 2011-2012, and the incentive levels prevalent in the countries in the scope of the RE-COST study at the end of 2012. Changes in incentives and support policies may significantly affect the results

		On-shore wind	Off-shore wind	Large Solar PV	Hydro	CCGT	Coal
Canada	Alberta	✓				✓	✓
	Ontario	✓ ↔ !		✓ ↔ !	✓	✓	
	Québec	✓			✓		
France		!	✓	✓		!	!
Germany		✓ ↔ !	!	✓ → ✗	✓	!	✓
Norway		✓	✗		✓		
Sweden		✓	✗				
Spain		✓ → ✗		✓ → ✗		✗	!
Japan		✓	✓	✓	!	!	✓

✓ Profitable ! Profitability issues ✗ Not profitable ↔ Uncertain → Impact of policy changes

Region/Technology pairs (scope of analysis) Does not exist or irrelevant Not included in the study

Figure 3. Region technology pairs – Business case simulations [23]

These simulations show that without policy support such as, incentives affecting revenues or costs, power purchases by the administration, schemes to reward generation attributes, etc., the business case of new plants is challenging. In the current market conditions investors have difficulties defining profit making projects based on RET and non-RET generation.

There are exceptions to this general rule. Gas-fired plants in Alberta, where low prices of gas significantly reduce the ultimate costs of generation, may provide positive margins to investors. At the current low prices of emissions, large coal fired plants in Germany using relatively low priced coal, also have positive business cases. New thermal plants in Japan could also provide sufficient revenues to realize positive margins. The rest of the region/technology pairs require appropriately defined policy support to interest investors.

Optimization of policies – Lessons learned. The analysis of the behavior of the region/technology pairs included in the scope of RE-COST has highlighted a number of features that contribute to increase the effectiveness of policies geared to developing new RET generation.

A. – Policies for electricity generation must be comprehensive. Policy makers should assess the potential impact of any new policy over the full generation mix of the zone, including RET and non-RET generation, new and existing plants, the transmission infrastructure, and the electricity markets.

With increasingly high levels of RET generation, policies that do not consider indirect impacts are likely to cause unintended, and potentially damaging consequences in parts or in the totality of the electricity sector. Examples of aspects that need to be considered by most policies include dimensioning the grid to

of the business case of a plant → represented as two signs in some region/technology pairs. Business case is profitability (revenue-cost), including costs of connection to the grid and strengthening the grid, and excluding transmission costs. Incentives and support have also been included when they could be identified (not hidden).

[23] Include direct incentives and policy support

enable connection of larger scale deployment of non dispatchable RET; defining provisions to prevent that system relevant plants are de-commissioned; and ensuring a good balance of dispatchable and non-dispatchable generation.

B.- It is necessary to maintain the incentives that have proven to be effective to develop RET, in so far there is not a level playing field between RET and non-RET generation. Examples of policies that appear to provide interesting business cases to investors include: the FITs for on-shore wind in Germany, the offsets scheme in Alberta, the auctions of on-shore wind in Quebec and of off-shore wind in France, the green certificates system for on-shore wind and hydro in Norway and Sweden, and the FIT for solar PV and wind in Japan. To support the deployment of RET, it is of particular relevance to maintain priority feed-in in the regions where it exists, such as Spain, France, and Germany.

When incentives do not exist, or when are not appropriately defined, the business case of new generation does not hold. Examples include off-shore wind in Germany, Norway, and Sweden, where the current incentive systems are not fully adapted to the specific cost and technical requirements of this technology. Another example is Spain, where the latest moratorium in incentives to RET has negatively affected the business case of new RET plants; and where excess supply, and competition with RET damage the business case of non-RET generation.

C.- Policies must be adapted to the business case of generation. This could be accomplished by using different mechanisms:

- **Policies that do not raise the interest of investors should be changed,** to better adjust them to the technology and market situation where they operate. One example is the auctions for off-shore wind and solar PV in France, which have become the main incentive system for these technologies when the previously defined FIT schemes did not sufficiently entice investors.
- **Policies have to keep pace with the relatively fast evolution** of costs and operating conditions of new RET; either by incorporating provisions that enable their gradual adjustment, or by being revised over time.
    - Examples of **policies that incorporate provisions to adjust incentives** include: auctions of on-shore wind in Quebec, which adjust the level of payments over several years; the German incentive system for wind and solar PV generation, which features a degression scheme for the FIT payments over time; and the FIT for large solar PV in Japan, that has been recently reduced to better approximate the evolving costs of this technology.
    - **Some policies could be further fine-tuned** to increase the interest of investors. Examples include the green certificates system of Norway and Sweden and the provisions associated to the FIT in Germany for off-shore wind[24]. Under consideration could also be the FIT for on-shore and off-shore wind in Japan, where currently no difference is made between the two technologies.
- RET could also be fostered by **strengthening the policies to reduce emissions:** These measures should be consistent and rigorous for all polluters, include minimal exceptions, and reflect the true social costs of emissions.

[24] Some of the provisions of the FIT system in Germany as defined at the end of 2012 result in tight business cases for most on-shore wind and large PV plants. However, the direct marketing scheme appears to provide enough revenue to investors, thus enabling the continuous addition of new RET plants in this country

- Of particular importance is to **reduce the length and complexity of the authorization processes** for new generation – both renewable and non-renewable. Difficult as this may be, given all the constituencies involved, any successful measure in this aspect is likely to increase the interest of investors and developers.

Improving the quality and accuracy of the information used by policy makers is critical to ensure optimal adaptation of policies: Databases that mix data from different regions, or that include a significant proportion of older plants do not provide an accurate picture of the costs of different generation technologies today. Using current, region specific data is essential to maximize the effectiveness of regional, national, and supra-national policies.

D. - Introduce incentives that are clearly visible. Optimizing policies and attaining the support of the public and of key stakeholders (investors, supply chain, consumers, and taxpayers) requires that the provisions and implications of each incentive are clearly visible. Increasing the depth and the quality of the information available is likely to contribute to a better understanding of the impact of policies and may result in higher levels of public support to well-crafted policies.

A number of mechanisms can contribute to increase the overall transparency of existing and future support measures:

- **Giving priority to incentives that are easier to track**. Incentives, such as green certificates, and offsets provide support that, to a certain extent, benefits from the features of a market based approach, such as visibility, self-adjustment and alignment of demand and supply. FITs, power auctions, and other incentives, whose compensation levels are defined by policy makers, also provide a significant amount of information about their objectives, the size of funds provided, and the conditions that recipients must fulfill to receive them. In contrast, compensation schemes based on tax provisions or on direct grants to specific plants are somewhat opaque. Assessing the size of the funds provided, as well as the actual impact of these incentives is a challenge, even for experts.

- **Clearly assessing, and communicating the impact of all incentives**. An example of this feature is the inclusion in the power bill of an analysis of the impact of RET incentives in the final price of electricity. But it would be recommendable to also report the cumulative cost of support policies for all generation technologies, including RET and non-RET.

- **Improving over time the quality of information available to the public:** Policies and provisions should be supported by clear, accurate, and consistent information and background analysis that enables stakeholders and the public to understand them.

Defining optimal policies for the electricity sector is not straightforward. Balancing the needs and objectives of the many actors that operate in a complex sector requires careful consideration, based on up-to-date and accurate information. RE-COST aims to contribute to the efforts of policy makers, providing insights that can be built in the definition of norms and policies.

2. DECISION MAKING PROCESSES FOR POWER GENERATION INVESTMENTS

Defining successful policies to increase the penetration of RET requires a deep understanding of the factors that influence the decision to invest in generation projects. In principle, investors approach investments in energy generation in the same manner as they approach any other investment: **They assess the returns that will be obtained in comparison with the required investment. These returns have to be commensurate with the level of risk of the project.** The combination of risks and returns is defined as "the business case" of a plant or project.

But different types of investors seek different types of returns, and different levers affect the business case of a generation project in a very diverse way. General assessments are not particularly useful to define well adapted support policies. It is necessary to descend to the details. This section evaluates the most relevant factors in the decision making process of investors and discusses how they may be affected by different drivers, including technology advances, the market situation, and support policies and incentives. A tool – the RE-COST model – has been used to simulate and assess the impact of these different factors. The focus, conventions, and reference values used by the RE-COST model have been summarized in the blue boxes at the end of each sub-section, to allow a better understanding of the hypotheses made, and the inputs used.

2.1 Actors and sources of capital in power generation

Figure 4 provides an example of the different types of actors in the value chain of electricity generation. The term "investor" is used in most studies to refer to the actors marked with an "X" in the table only. However, this report takes a more extensive view, describing as investor: "*any private or public participant in the supply chain of a generation project that uses funds to obtain quantitative or qualitative returns*".

ACTOR	DESCRIPTION	
Equipment manufacturers	• Engineering companies. • Suppliers of equipment and services (turbines, solar panels, blade logistics). • Plant developers and construction companies.	X
Generation companies	• Private and public producers of electricity, including a wide array of entities. For instance: – Large, consolidated utilities with dozens of generation units, and multi-national focus. – Small producers with a few generation units and specialized in one technology.	X
Transmission and distribution	• TSOs or Transmission System Operators are public or private companies that own and operate the transmission infrastructure that transports electricity from the production site, to the consumer through national, regional and local networks (the grids). • DOS or distribution companies that maintain the electric network and/or are billing agents in the areas where they operate[25].	
Wholesale/traders	• Companies that trade buy and sell electricity. Participants in the electricity markets.	
Retailers	• Secure the supply of electricity to their customers.	
Regulators	• Include policy makers, government advisors, legal supervisors and other entities that define and enforce the rules governing the electricity sector in a given location	
Market operator	• Institutions that own and/or operate the markets and exchanges where electricity, and electricity related products (e.g. futures, green certificates, other) are traded.	
Capital providers	• Include private and public institutions that provide the capital required to design, build, operate and decommission a power plant	X

Figure 4. Examples of investors and other actors in the value chain of electricity generation

[25] Source: Canada centre for Energy - www.centreforenergy.com/AboutEnergy/Electricity/Distribution/Overview.asp?page=8

Figure 5 shows an example of key actors in the value chain of the power supply in Germany.

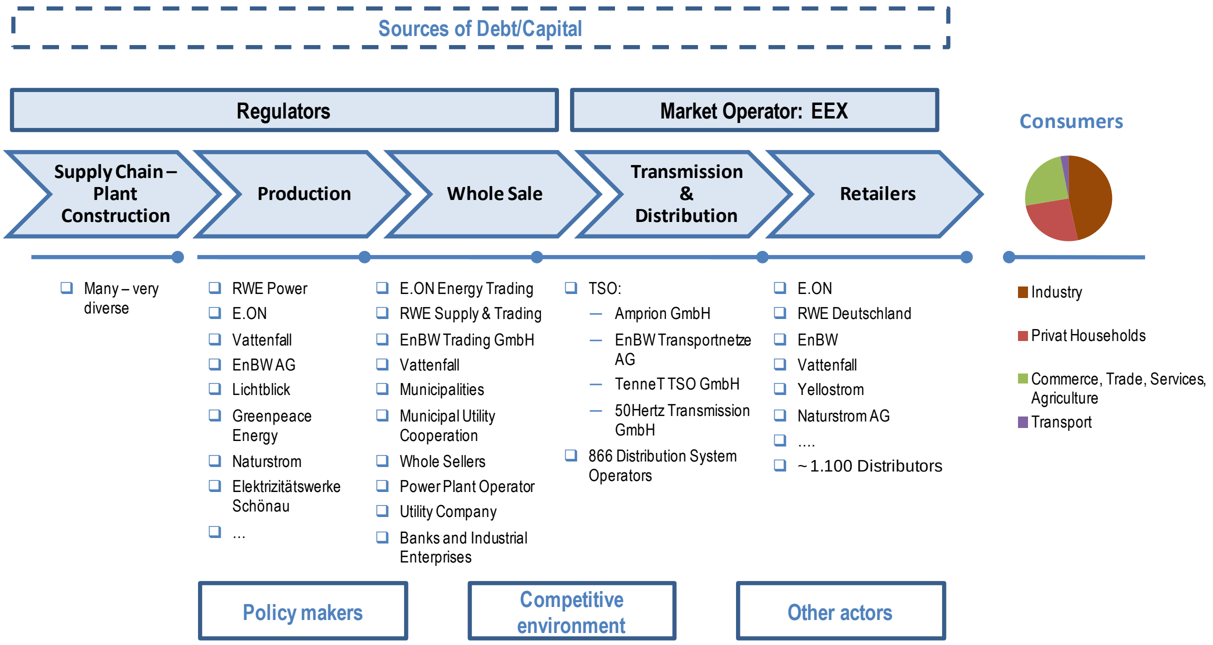


Figure 5. Germany – Examples of actors in the value chain of electricity generation

Some investors are public and other private; but both types of investors take a portfolio approach to the evaluation of investments, basing their decisions on a combination of qualitative and quantitative factors:

- **Private investors** may include in their decisions a number of factors beyond the business case of a project. For instance, utilities assess the impact of each new plant in their existing generation basis (portfolio effect); the possibility of storing intermittent generation of a variable plant in other (dispatchable) plants; how to offset the taxes assessed to one project with the tax allowances generated by another project; how a project may increase their experience with a new technology, etc. Whenever possible, private investors attempt to quantify these additional factors, even when some of them may be to a large extent qualitative.
- **Public investors** may include in their decisions parameters not necessarily focused on a strict analysis of return and risks. Examples of high priority factors for public investors include: ensuring the security of supply of energy, fostering the national development of new technologies, creating jobs, controlling emissions, lowering electricity prices to inhabitants of the country, etc.

The main focus of this report is the quantitative aspects of an investment. However, other factors have also been taken into consideration to provide a balanced view of the decision making processes of different types of investors.

2.2 Key elements in investment evaluation

The design, construction, operation, and decommissioning of a power plant are governed by a number of contracts established between different parties. Figure 6 shows an example of the contracting structure of a wind power project.

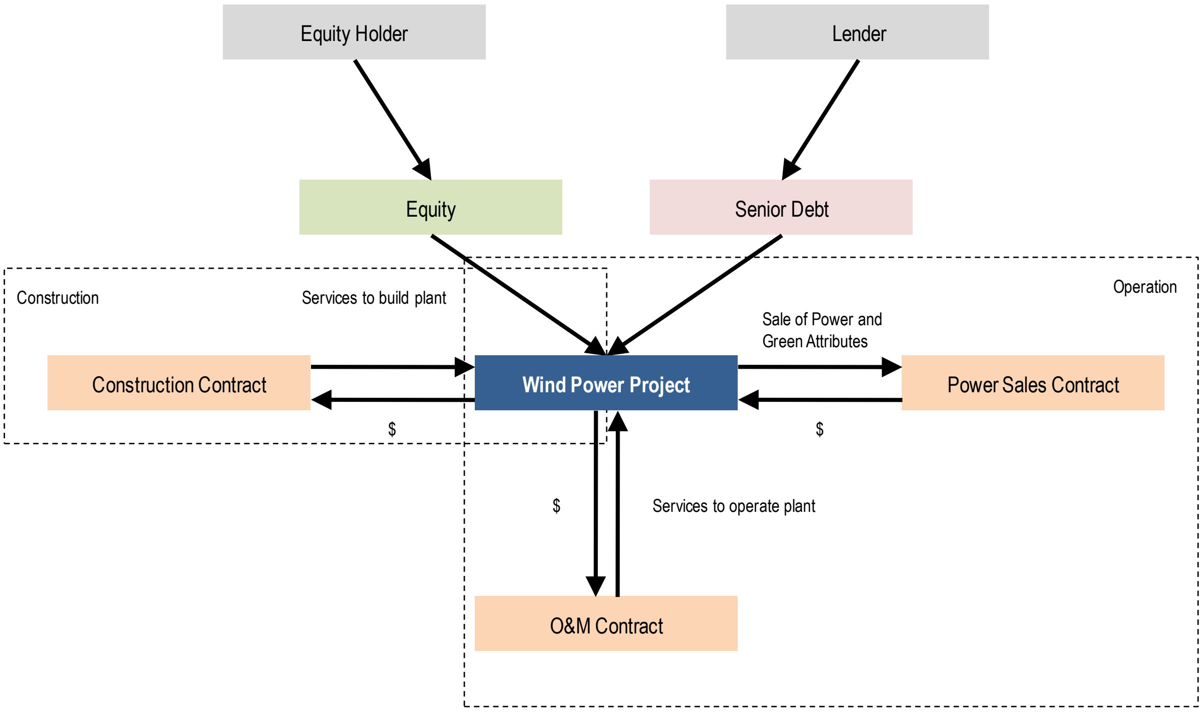


Figure 6. Example – Structure of an operational wind power project[26]

The returns and risks of each of these transactions will be influenced by a large number of factors. These factors are not the same for the various actors, participants and influencers of the project, who have different points of view, requirements, needs and approaches to evaluating power generation projects. However, most investors, if not all, consider five elements in their decision making processes:

- **Cost of the project:** Technical, market, financial and other considerations affect the cost of a generation project. Investors carefully consider the current and potential future costs associated to an investment. Sections 2.5 and 5 extensively describe the sources of costs of different generation technologies, as well as the processes used by investors to evaluate these costs, and to minimize them to the extent possible.
- **Revenue of the project:** Investors also devote significant effort to forecast, and influence in some cases, the revenues associated to a project. It is convenient to separate the discussion of costs from that of revenues, because the mechanisms used by investors to calculate them are quite different, and because the confidence levels of the calculations of costs and revenues may be very dissimilar too. Section 2.6 describes some of the most important sources of revenue of a generation plant, and how they have been incorporated into the RE-COST model.
- **Sources of financing:** Different sources of financing may be used in electricity generation. This study puts particular emphasis in the typical sources of financing used in the countries and technologies in the scope. Sources of financing include (1) loans from financial institutions, (2) capital from private and public

[26] Source: Private financing of renewable energy – a guide for policy makers – UNEP (2009), Prysma analysis

sources, and (3) other direct or indirect ways to raise capital, such as guarantees, bridge loans, grants, etc. Different sources of financing are described in Section 2.3.

- **Project risk:** Investors, financial institutions, and other participants in a generation project have different expectations with respect to risk and reward. These expectations influence the viability and economics of the project under consideration. Some projects may be financed only by investors that expect relatively low returns coupled with low risks (for instance, insurance companies financing solar PV projects). Other projects require the participation of investors with appetite for large risks and returns (R&D projects related to new technologies). Section 2.4 provides additional details on the sources of risk of investments in generation and their potential quantitative impact in the business case of a given plant.
- **Incentives and policies:** Policies and regulations are also factored in the decision making process of actors and investors. In fact, in some cases they are the primary factors considered to evaluate an investment proposal. *Which is the tariff level*? is one of the first questions asked by investors when evaluating their potential participation in RET projects. Policies influence each element of the business case of a generation plant, providing policy makers with a large array of tools to influence the decision making processes of investors. Policies and regulations (country specific) are extensively described in Section 6.

2.3 Sources of financing

Different types of investors use different sources of capital and financing instruments to acquire capital. The graph below shows examples of typical mechanisms used in different stages of the life cycle of a generation technology.

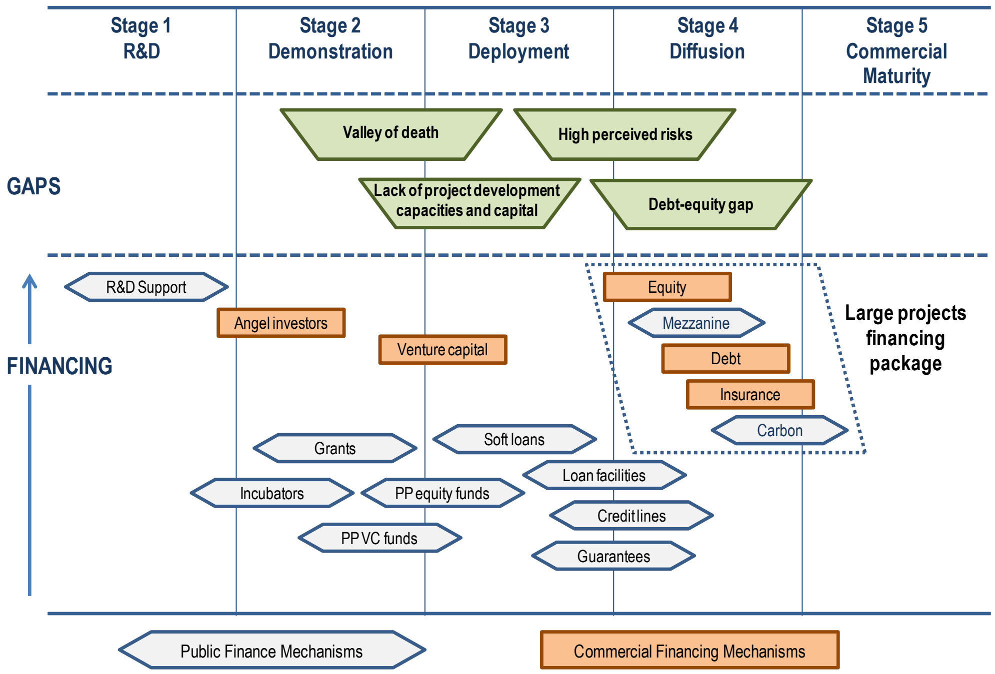


Figure 7. Examples – private and public mechanisms to mobilize investments in electricity generation[27]

Some of the most relevant sources of funds include:

[27] Source: UNEP – Public finance mechanisms to mobilize investment in climate change mitigation, Prysma analysis

- **Financing institutions** that provide loans to investors[28]:
  - **Commercial banks** finance companies and projects through a variety of instruments. These instruments include corporate lending, project finance, mezzanine finance, and project refinancing.
  - **Public banks and funds** provide loans to projects and companies, using public funds.
- **Commercial equity investors** consist of a variety of companies that take stakes in different types of projects with different associated risks:
  - **Venture capital (VCs) funds and angel investors** raise capital from a variety of sources. VCs usually have a higher risk appetite than other investors. They are a good source of capital for riskier projects or technologies, but demand very high rates of return to compensate for the higher risks they take (25-300% IRR).
  - **Private equity funds** raise capital from different sources, and have a medium level of appetite for risk. They require lower IRRs than venture capital funds (25-50% IRR).
  - **Pension funds** tend to invest in projects with lower levels of risk, and which generate steady cash streams to cover for the obligations they assume with the pension fund holders (10-20% IRR).
  - **Insurance companies** are highly regulated. They are required by law to invest their capital in projects and companies with relatively low levels of risk. As a consequence, they may accept relatively low levels of returns (3-7% IRR).
  - **Other funds:** investment funds, infrastructure funds, etc.
- **Public sources of capital.** Capital may also be directly obtained from public sources in the form of grants or other mechanisms. Examples of public sources of finance include:
  - **Project development grants:** loans without interest or repayment until projects are financially viable. In some cases, non-viable projects may not be required to return the funds they receive (non-refundable grants).
  - **Loan softening programs** are grants to help commercial banks and other providers of capital that allow them to lend their own capital to end-users in better terms (lower rates) than the prevailing in the market (commercial rates).
  - **Inducement prizes and other grants:** capital provided to stimulate technology development.
  - **Others.**

Projects based on proven and mature or maturing technologies that operate in developed countries tend to use as main sources of financing the mechanisms included in the box with a dotted border in Figure 7. The financing packages are provided by a combination of commercial lending institutions, commercial investors with different appetite for risk, public institutions, etc.

2.4 Assessment of risks

The perceived level of risk of a generation plant or project is a critical factor in the decision making process of investors and policy makers. A large number of interrelated factors influence and determine risk. The table below describes the typical risks that are included in the assessment of the business case of electricity generation. Technical and project risks are extensively described in other RETD reports[29].

[28] Source: Private financing of renewable energy – a guide for policy makers – UNEP (2009), Prysma analysis

[29] Source: Risk Quantification and Risk Management in Renewable Energy Projects (2011) – Available at http://iea-retd.org/wp-content/uploads/2011/11/RISK-IEA-RETD-2011-6.pdf (as of 05/2013)

RISK	TYPE	DESCRIPTION	EXAMPLES - COMMENTS
Country	**Country risk**	Includes characteristics of the country in which the plant operates, such as stability, capital flows, strength of the legal system, etc.	All the countries included in the analysis have low levels of country risk, but the impact of the financial crisis in Spain results in a higher perception of country risk to some investors.
	Political	For a given country, different political regimes may pose different levels of risk – especially if changes in government may result in different policies.	For instance, France and Japan currently are in a process to revise their energy policies now. Governments of different sign may be more or less prone to stimulate a given generation technology.
Policy and regulatory	**Clarity**	Extent to which different aspects that may influence the case of generation are regulated in a clear and unambiguous way.	All the countries in scope have clear policies. But in some developing countries with less experience in electricity legislation and with fewer precedents it may not be clear how a norm has to be interpreted.
	Number of regulations	Regulations and rules that can add additional compliance burden to investors.	Excessive and lengthy permission processes, with many requirements and many institutions involved, increase the chances that a project will not even be started (solar PV and off-shore wind).
	Stability	Stable or predictable regulations reduce the level of risk of investors because they can adapt to them.	Excessive and frequent changes to applicable policies or retroactive policies significantly increase the uncertainty associated to the future returns of an existing or projected plant, thus resulting in a higher risk to investors. (Spain)
	Environmental and social	Policy impact of environmental and social factors that may affect the generation project.	All the countries in scope of this study have national environmental and social policies. In addition, local and regional governments define specific provisions that affect the business case of a generation project. For instance, local content requirements to maximize job creation in a province affect the returns of the local generation plants (Quebec, RFPs in EU countries, etc.)
Financial	**Economic**	Inflation and others	The countries in scope do not have high inflation levels, but given the global nature of the supply chain, uncertainty over inflation in China may increase the risk of a solar PV project in Europe.
	Financial	Prevailing interest rates, asset liquidity, etc.	Financing rates in a given country or region .
	Currency	Occurs when the components of costs and revenues are in different currencies. Fluctuations in currency values may affect the outcome of the project.	The model is able to compute the impact of currency fluctuations. But most of the examples provided do not consider them. It is implicitly assumed that currency variations are hedged in an appropriate way[30].

[30] Currency assessments are conducted in any generation project. The electricity generated by the plant is sold in local currency and the lender or investor may have to be compensated in another currency. Evaluating currency risk in detail is outside the scope of this report.

RISK	TYPE	DESCRIPTION	EXAMPLES - COMMENTS
	Security	Assurances provided to lenders and capital providers that they may take possession of the assets if there is a default and continue operating the plant.	This is not a significant issue for the countries included in the study. Their legal frameworks provide high levels of assurance to investors. However, foreign investors in a region may assess higher risk to a project than local participants to account for the difficulties of operating in legal framework different from their own.
Technical and project risk	**Technology**	Risks associated to the technology used in the project, its level of maturity, operating history, data availability, etc.	Technical and project risks include a large number of factors. This section evaluates the sources of technical and project risks, as well as the impact of regulations and policies of these types of risks.
	Construction	Risks involved in the construction of the plant, performance of contractors and supply chain, timing of build, etc.	
	Operation	Staffing and costs requirements, existence of suppliers to provide support for operation, prevailing contracts and rates during operation.	
	Decommissioning	Applicable regulations, , existing supply chain and experience in the decommissioning of plants.	
Market risk	**Global**	Trends in economy influence demand of electricity, and therefore the sales volumes of the generation project.	The financial crisis is contributing to a reduction of power demand in many of the regions in the scope of this study. This increases the risk of current and future generation projects and makes more uncertain the forecast revenues.
	Future prices	Provisions by specialist and existing markets as of the prices of factors costs (steel, PV modules, coal, gas), electricity prices, emission prices, etc.	The potential variations and the level of uncertainty associated to factor costs result in higher capital and operating costs of a project. They also affect the levels and uncertainty of revenues from electricity and of revenues from other sources.

Figure 8. Typical risks included in the assessment of the business case of electricity generation

2.5 Cost of electricity generation – Evaluation and comparisons

Investors assess potentially relevant cost drivers, and carefully evaluate them to quantify costs, identify when these costs will be recognized, and forecast when cash outlays will be necessary.

The confidence levels of these assessments may be very different. In some cases, investors precisely know the size and timing of some costs. For instance, when purchasing a power plant already built, the one-time costs associated to the acquisition are to a high extent determined. However, even in turn-key acquisitions, some costs are not accurately known, either because they will take place in the future, or because of other reasons. Investors build cost models that reflect the actual behavior of the costs of a generation project with a higher or a lower degree of accuracy, and make decisions based on the combination of [value ↔ uncertainty].

Key elements that have been used to define the evolution models used in this study include:

- Use of LCOE as a relevant, although not the only one tool, to compare costs of generation.
- Simplification of the analysis of the impact of exchange rates.
- Application of a lifecycle approach to categorize and compute the components of cost of generation.

Levelized Cost of Electricity – (LCOE): LCOE corresponds to the cost of a generation project assuming the certainty of production costs and the stability of electricity prices. The formula used to calculate and levelize the cost of energy is the following:

$$LCOE = Elec_{price} = \frac{\sum_t \left((I_t + O\&M_t + Fuel_t + C_t + D_t) * (1+r)^{-t} \right)}{\sum_t (Elec_t * (1+r)^{-t})}$$

$$Elec_{price} = \text{The constant price of electricity}$$
$$(1+r)^{-t} = \text{The discount factor for year t}$$
$$I_t = \text{Investment costs in year t}$$
$$O\&M_t = \text{Operations and Maintenance costs in year t}$$
$$Fuel_t = \text{Fuel costs in year t}$$
$$C_t = \text{Carbon costs in year t}$$
$$D_t = \text{Decommissioning costs in year } t$$
$$Elec_t = \text{Electricity produced in year } t$$

Figure 9. LCOE formula[31]

LCOE may have some drawbacks when it is used to evaluate the business case of generation:

- It includes too many variables. This may make it difficult to trace cause and effect.
- It is just a partial figure; it does not reflect total costs, but a ratio.
- Many investors do not consider the levelized cost of electricity as an essential parameter to make decisions. They use equivalent indicators, or the same parameter with different names: unit cost, cost per MWh, etc.

However, LCOE also has significant advantages:

- It allows comparisons of costs across plants with different technologies, sizes and characteristics. Using LCOE makes it possible to compare the capital costs of a 2 MW solar PV plant with the capital costs of a 600 MW coal-fired plant (at least quantitatively).
- It is used by many policy reports in the electricity sector.

LCOE has been extensively used in this report. But to provide a more accurate picture of the decision making processes of investors, it has been complemented by other parameters also frequently used in assessments of power generation projects (P&L, IRR, NPV, margins, etc.).

Currency exchange assessment and impact: Most investors in power generation operate in more than one currency and need to consider exchange rates as a key factor that significantly influences the costs and the revenues of a plant or project. The level and potential evolution of exchange rates may be a determinant factor in whether the business case will be positive or negative. Usually investors use models which include scenarios of currency evolution, and in some cases hedging analysis.

[31]Source: IEA-NEA. Projected costs of generating electricity – 2010 Edition

RE-COST approach to modeling exchange rates: This report does not include extensive assessments of the impact of exchange rates. Such analyses are outside the scope of this study, and may be better covered by a report on international finance or risk analysis. However, a number of analyses of the impact of exchange rate variations have been performed revealing that the impact of variations in exchange rates over cost and revenues is well within the rate of error associated with the model (lower than 5%).

In order to allow comparisons between countries, local currencies have been converted to US dollars using the conversions rates depicted in the following table.

EU €*	NOK	SEK	¥	CA $	US $
1.30	5.68	6.65	81.21	0.99	1

Figure 10. RE-COST model – US Dollars per currency unit [32]

Lifecycle approach to cost calculation: This report follows a lifecycle approach to identify and evaluate the costs of a generation project, as depicted in the diagram shown in Figure 11. This presents two main advantages.

- It enables a better understanding of the mechanisms that influence costs, associating cost drivers with resulting costs as they materialize during the lifetime of the plant.
- It approximates how investors think about a project, even when in some cases they do it implicitly, not explicitly.

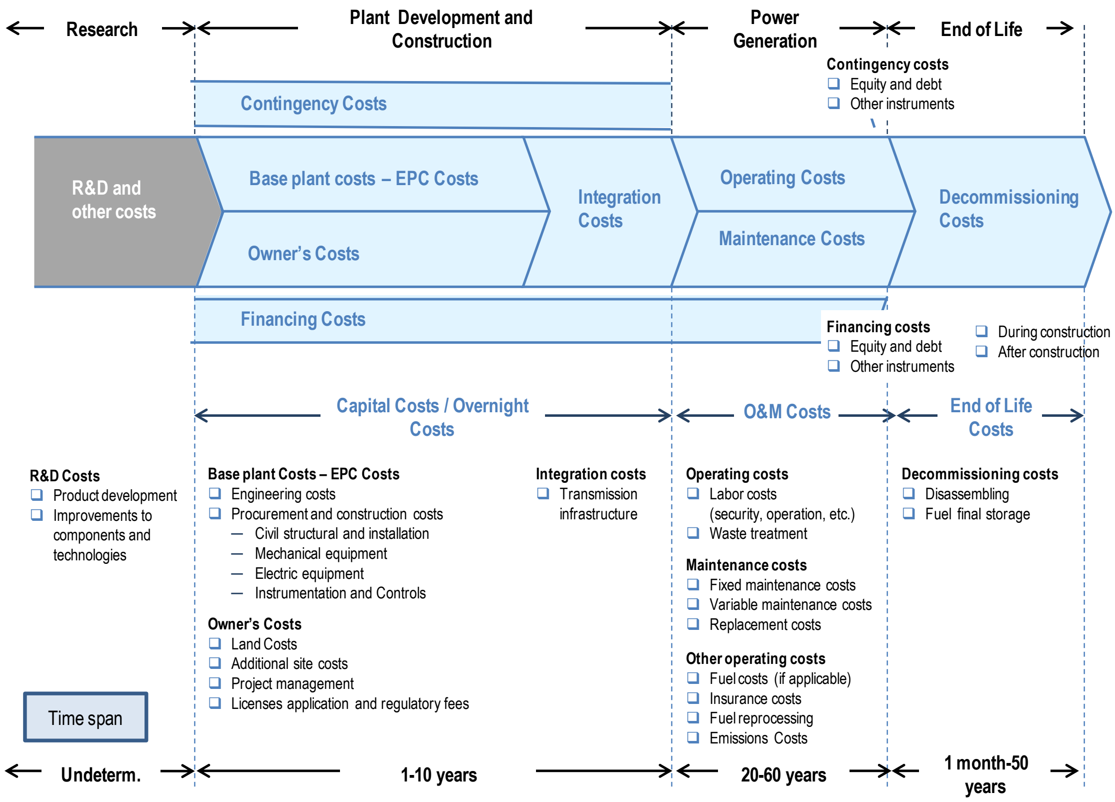


Figure 11. Life-cycle approach to calculate costs of a generation project[33]

[32] Source: Board of Governors of the Federal Reserve System – Average Fourth Quarter 2012 (October to December).
*US$/€ as indicated in the source. Please note that throughout this report the same exchange rate has been used to enable comparisons between variables quoted in different currencies. This allows the reader to easily transform US$ into other currencies, but introduces an error due to variations over time of exchange rates..

2.5.1 R&D costs

Most investors do not include R&D in the costs of a specific plant for a number of reasons:

- When dealing with mature technologies, such as wind, solar PV, and thermal generation, the original R&D costs may have been incurred many years prior to the cost assessment. It may not be possible to trace the impact of ancient R&D expenditures to costs of present projects.
- The impact of expenditures and investments in R&D may be embedded in the costs of the components and systems of a plant, and may not be specifically identified. Therefore, including costs of innovation, research, and development in the operating costs of a given plant may result in misleading results.

This does not mean that investors disregard the impact of R&D costs and grants. Very likely the technologies included in the study would not be in operation if they had not counted with R&D, or with other development grants at some point in the past. An example is operating off-shore wind plants in Japan and Norway/Sweden[34]. They have received development grants that have enabled them to be commissioned and to operate today.

RE-COST approach to modeling R&D costs: The model allows to add the impact of R&D costs or grants to a given generation project, if they are known. But R&D costs are considered by the study and by the supporting calculation model only when they may result in a grant or in other type of direct support awarded to a specific generation plant or project.

2.5.2 Capital costs

Capital costs are fixed, one-time expenses incurred in the purchase of land, buildings, construction, and equipments used in the production of electricity. Put simply, they include all the costs necessary to bring a plant to operation. Also included in the definition of capital costs are the expenditures associated to repowering. The recognition of capital costs in financial and tax returns (depreciation) may be spread out over many years.

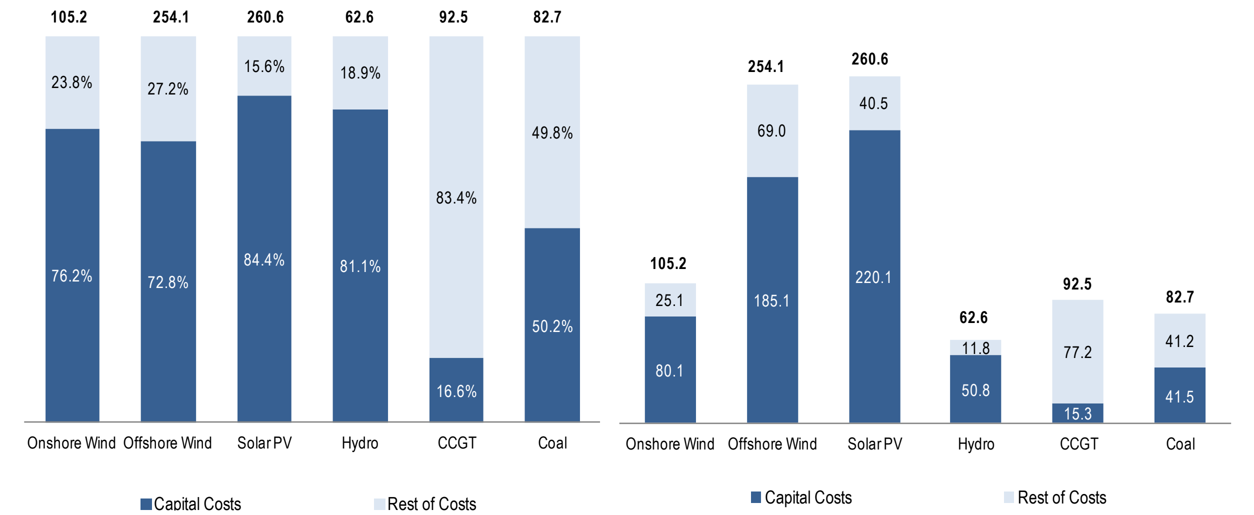


Figure 12. LCOE breakdown per technology – Capital costs vs. rest of costs (%, US$/MWh) – Example Germany[35]

[33] Source: Prysma analysis

[34] The Lillgrund Offshore Wind Farm (Sweden) received an investment support of roughly 20 M€. Source: Offshore wind power policy and planning in Sweden – Elsevier.

Japan, through its Ministries MOE and METI is developing some demonstration projects (1) Chosi, Chiba / Kita-kyusyu, Fukuoka (2012), (2) Goto islands, Nagasaki (2013) and (3) Fukushima (2013-2015). Source: Brief overview of Japanese offshore wind projects and initiatives – Ministry of the Environment Government of Japan.

[35] Country specific discount rate, equity 60% and debt 40%, technical average case

Servicing capital costs is one of the most important factors determining the economic competitiveness of a power plant because of the comparatively large size of capital costs vis-à-vis other costs. Figure 12 displays an example that shows the proportion that capital costs represent over total costs of generation[36]. The most capital intensive technology is solar PV, due to high costs per MW, and relatively low generation efficiency. When costs are annualized or levelized, the true impact of solar PV capital costs is made evident.

Given the significant impact that capital costs have in any generation project, it is essential that policy makers attain a very detailed understanding of their components and behavior. In order to better assess capital costs, they have been grouped in three types of costs:

- Base plant costs or EPC costs (Engineering, Procurement and Construction costs).
- Owner's costs.
- Interest during construction (capitalized interest).

The sum of base plant or EPC costs + owner's costs is called **overnight costs** in many of the reports that evaluate costs of power generation.

EPC Costs include the costs of materials and labor necessary to design, plan, and build a generation plant. The proportion of labor and materials significantly varies by technology, as indicated in Figure 13.

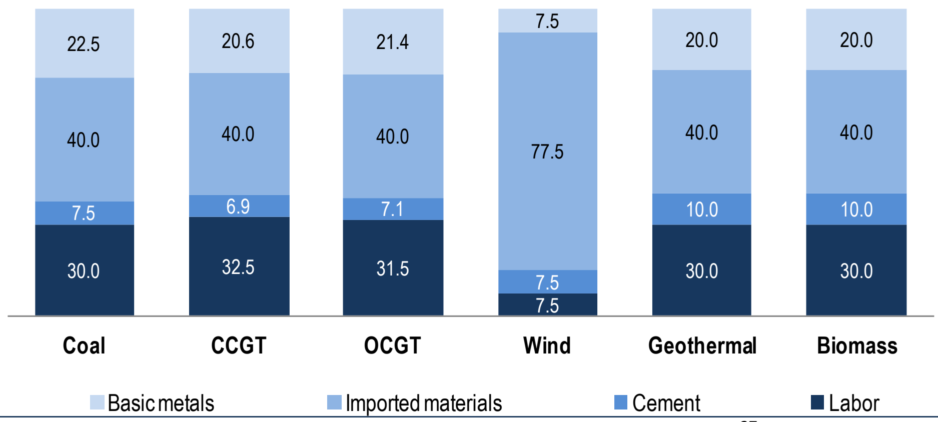


Figure 13. Capital costs – Weighting of factor costs by technology (%) – Example[37]

In spite of the globalization of the supply chain of plant construction, regional characteristics and applicable policies in a country or region may significantly influence EPC costs. Examples of factors that influence EPC costs in the regions considered by this study include:

- **Cost of labor**: Different countries have different average unit labor costs. Figure 14 depicts a comparison of labor costs in the countries in the scope. Other drivers also affect the ultimate cost of labor included in the capital costs of a generation plant. For instance, interviews have highlighted that unionization in Quebec results in more numerous, and expensive crews on construction sites for the same type of wind generator than in Alberta and Ontario, thus increasing the capital costs of RET plants.
- **Building codes:** Building codes also affect the processes, materials and construction standards of a plant. For instance, one of the factors that influence the capital costs of Japanese plants is the stringent building codes that apply in this country.

[36] Figures obtained from simulations with the RE-COST model

[37] Source: Review of inputs to cost modeling of the NEM – Queensland Competition Authority

	Canada	France	Germany	Norway	Sweden	Spain	Japan
Hourly Compensation Costs in manufacturing (2010)[38] in US$	35.67	40.55	43.76	57.33	43.81	26.6	31.99
Unit Labor Costs ratio (2008)[39]	0.475	0.720	0.710	0.319	0.604	0.668	0.493

Figure 14. Examples – Labor costs by geography

Investors factor these elements in their calculations of EPC costs. They also assess the risk associated to having different cost components quoted in different exchange rates; and in many occasions hedge against exchange rate variations in order to stabilize the value of a factor cost that may be significant.

Owner costs include the capital costs necessary to build and commission a power plant, other than those associated to purchases of equipment and procurement of outside services. This separation of capital costs into base plant costs and owner's costs may be slightly arbitrary; but it is also helpful, because it allows to consider separately costs mostly driven by local conditions, regulations, and administrative situations (mostly owner's costs), from costs that depend on international markets and supply chains (mostly EPC costs). Figure 15 shows examples of the main components of owner's costs.

Land costs	Cost of purchasing the land where the plant is located. In some occasions it also includes enough land for plant extensions and for the components of the grid necessary to connect the plant with the transmission network (substations, transformers etc.).
Connection costs	Also called "grid infrastructure" in some reports.
Pre-production costs	Training, equipment check-up, etc.
Project management	Fixed costs associated to the management of the project.
License application and regulatory fees	Additional fees levied on the project. In the countries considered in the study these costs are not large. But delays in the application and authorization processes may have a significant impact on the project.
Inventory costs (fuel storage, consumables)	Minimal amount of fuel and other consumables necessary to maintain the plant in operating conditions.

Figure 15. Components of owner costs – Examples

Engineering companies, developers and construction companies gather first hand information about the size and potential evolution of these costs during the project and construction phases, and build the resulting costs "bottom up". Developers and plant owners do not usually provide to the public, or to regulators detailed breakdowns of their owner costs. To provide approximations to the size and behavior of these costs for each region/technology pair in the scope, RE-COST has used different methodologies.

[38] Source: Bureau of Labor Statistics. U.S. Department of Labor.

[39] *Unit labor cost (ULC) measure the average cost of labor per unit of output and are calculated as the ratio of total labor cost to real output. UCLs show how much output an economy receives relative to wages, or labor cost per unit of output. UCLs can be calculated as the ratio of labor compensation to real GDP. It is also the equivalent of the ratio between labor compensation per labor input (per hour or per employee) worked and labor productivity*. Data extracted on 04 Oct 2012 from OECD Statistics

Connection costs consist of the costs associated to connecting the plant, and reinforcing the grid to integrate the new plant in the existing network. Connection costs, which may be very variable, depend on a large number of factors including the characteristics of the plant and the transmission grid, the generation technology, the policies and regulations that define the requirements to authorize connection, and the responsibilities of the plant developer and the TSO. The way in which the TSO assesses the charges to connect a new plant to the grid – called also "first connection" in some reports – is different in the countries assessed by RE-COST. Connection costs may be[40]:

- **Shallow:** the investor pays only for the cost of the line necessary to connect to the nearest point of the grid, and for the equipment required to support the connecting line. The TSO pays for the costs necessary to reinforce the grid. In countries and regions with shallow connection costs, the costs of upgrading the system are in some way socialized to all the producers. The expenditures of the TSO are usually recovered as transmission costs assessed to all the generators in the system. (See section 6.10 for a discussion of transmission costs)
- **Deep:** in addition to paying shallow costs, investors in a generation plant also have to pay the costs required to strengthen the existing grid. These investment costs may be significant if the plant is located far away, subject to a high level of generation variability, or if the generation and load of the plant are very high.

Examples of countries with shallow connection costs include Germany, Norway and Spain. Countries and regions with deep connection costs include Sweden and Ontario. Other countries and regions have systems that include a mix of shallow and deep connection features. For instance, France has a shallow connection cost scheme, but the investor has to pay for the connection costs, not to the nearest point in the grid to the plant, but to the nearest point where the adapted voltage level is available, and where the connection is technically possible. This point may be far away in some cases. In Japan the EPCOs are responsible for the transmission grids in the zones where they operate; therefore, they assume the costs of connecting new capacity to the grid – in this case, the TSO and the operator is the same. Alberta has a shallow connection system, but producers are required to provide a refundable security deposit based on the deep charges of connection.

Only the costs that are assessed to the investors in the plant are included in the simulations. The costs assumed by the TSO are not included in the business cases calculated in RE-COST. As depicted in Figure 19 and Figure 20, RE-COST considers connection costs as components of capital costs. The actual size of these costs has been evaluated through a combination of interviews (real cost paid to connect a plant in the database to the grid), and publications (average proportion that connection costs represent in total capital costs for each technology).

Pre-production costs can be estimated as one-month fixed operating costs (operating and maintenance labor, administrative and support labor, and maintenance materials). In some cases, these costs are as high as two years of fixed operating costs, because staff may be hired well before commissioning the plant.

Inventory cost. Different companies treat these costs in different ways. Either as an initial owner cost, or as an annualized cost that is included in variable operating and maintenance (O&M) costs. Typical, approximate values for gas- and coal-fired plants are displayed in Figure 16.

[40] ENTSO-E Overview of transmission tariffs in Europe: Synthesis 2012, www.futurepolicy.org (accessed on May 2012), Innovative Electricity Markets to Incorporate Variable Production – Alberta Province Report IEA-RETD (2008), Ontario Province Report IEA-RETD (2008), Prysma analysis

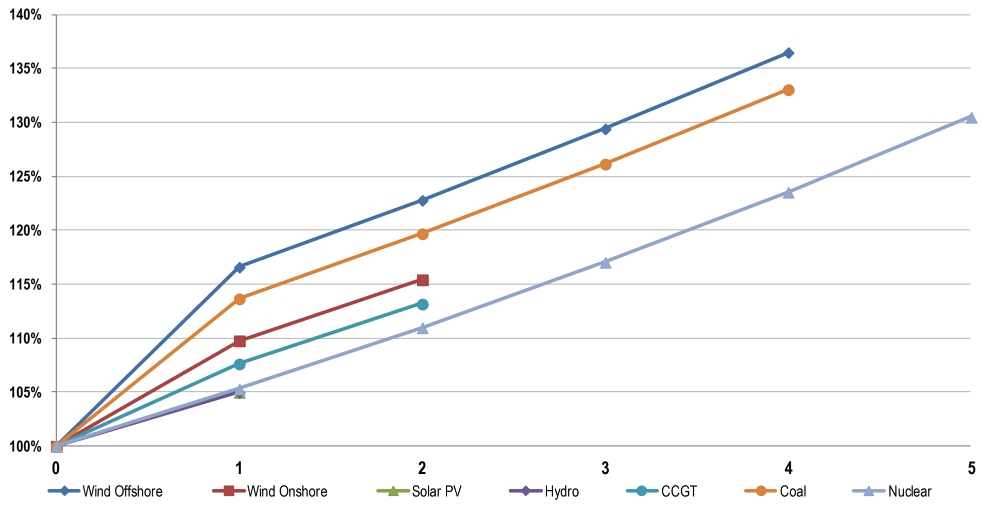
Type of unit	Nominal capacity factor	Fuel and consumable inventory days at 100% capacity
Base load	85%	60 days
Intermediate	30-50%	15 days
Peak	10%	5 days

Figure 16. Example – Estimates of consumable inventory (approximations)[41]

Interest during construction (IDC) consists of the interest generated by loans provided during the construction of the plant, before the plant begins to generate revenue. Examples of the most important levers of IDC include:

- Timing of purchases and schedule of payment.
- Effective interest rates.
- Delays in commissioning the plant.

IDC are costs that are not covered by revenues from the sale of electricity and electricity attributes. Therefore, investors try to minimize them to the extent possible. A consistent complaint of developers and utilities is the very negative impact that delays due to exogenous factors cause to their projects. Delays not only affect the costs of a plant, but its actual viability. The uncertainty caused by delays may force a developer to abandon a project, even if on paper the business case appears as positive.



	Wind Onshore	Wind Offshore	Solar PV	Hydro	CCGT	Coal	Nuclear
Standard Construction time(years)	2	4	1	1	2	4	5

Figure 17. Example – Sensitivity of capital costs to variations in construction time

Figure 17 shows a simulation of the sensitivity of capital costs to delays in plant commissioning for different technologies. Figure 18 shows the impact, in the sizes of capital outlays, of variations in construction times for CCGT at different interest rates.

[41] Source: Interviews, RE-COST database of plants and projects.

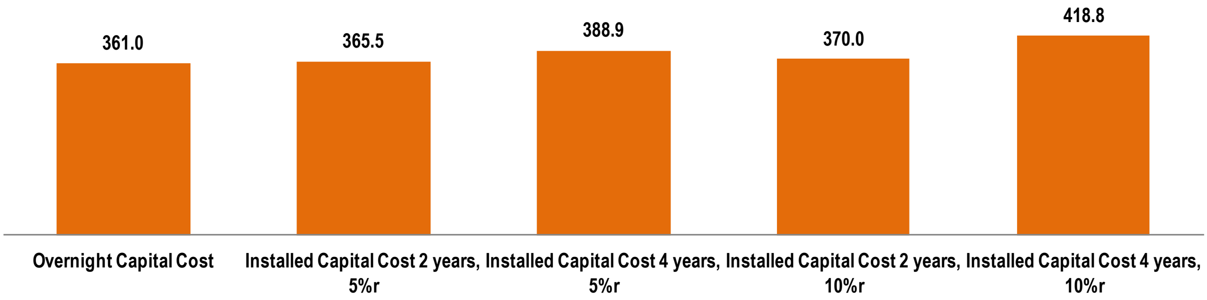


Figure 18. CCGT – Delays in construction (million US$) – Plant size 400 MW

RE-COST approach to modeling capital costs: The main challenge associated to evaluating capital costs using a database of real plants and projects has been to define a consistent baseline. Total capital costs and breakdowns of capital costs were obtained from different actors, including investors, fund managers, utilities, developers, and engineering companies. Each of these actors had a different view of how to allocate and report their costs. This resulted in different values for the same cost item, and in different ways to name the same cost factor. The next tables summarize the level of detail reached in the data collections process.

	On-shore Wind	Off-shore Wind	Solar PV	Hydro	CCGT Coal
EPC 1	Turbine	Turbine	Modules	Reservoir	Civil Engineering
EPC 2	Foundation	Foundation	Civil Engineering	Tunnel	Mechanical Engineering
EPC 3	Electric installation	Electric installation	Mechanical Engineering	Powerhouse	Electrical engineering
EPC 4	Indirect costs[42]	Indirect costs	Electrical Engineering	Indirect costs	Indirect costs

	On-shore Wind	Off-shore Wind	Solar PV	Hydro	CCGT Coal
Owner's 1	Land cost	Pre-financial cost	Land cost	Total owner cost	Land cost
Owner's 2	Pre-financial cost	Grid infra-structure	Pre-financial cost		Pre-financial cost
Owner's 3	Grid infra-structure[43]	Spare parts	Grid infra-structure		Grid infrastructures
Owner's 4	Spare parts	Project mgmt.	Admin. fees and other		Spare parts
Owner's 5	Project mgmt.				Project management and others

Figure 19. Components of EPC and owner costs per technology[44]

Figure 20 shows a quantitative example of the breakdown of capital costs for different plants included in the databases.

[42] Indirect costs include engineering, distributable labor and materials, craft labor overtime and incentives, scaffolding costs and start up and commissioning costs.

[43] Grid infrastructure: cost of connection to the grid and upgrading during the construction of the plant if borne by the investor.

[44] Source: Prysma analysis

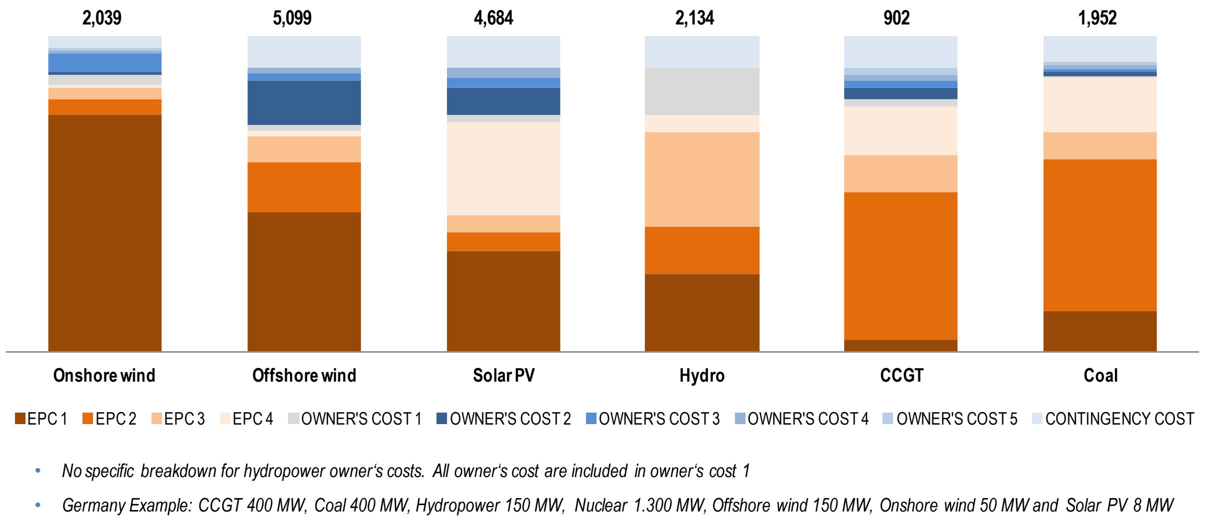


Figure 20. Breakdown of capital costs per technology (US$/kW) – Comparison[45]

2.5.3 Contingency costs

Contingency costs include all the unplanned costs that arise during the construction and operating phases of a plant. Investors usually calculate them as a percentage of total capital costs. The actual percentages used depend on many factors, and may significantly vary. Examples of average percentages would be: 5% in solar PV projects, 10% in on-shore wind farms and CCGT plants, and up to 5-12% in the case of coal-fired plants[46].

In some cases, the uncertainty associated to contingency costs can be mitigated through a turnkey construction contract, where all the costs are defined from the beginning and most of the overruns are assumed by the construction company.

RE-COST approach to modeling contingency costs: Very few accurate data for real plants were obtained in the data collection process. First, because actors were reluctant to recognize they have had overruns in specific plants. Second, because calculating the exact additional cost due to the overrun, and how to allocate it to the generation costs of the plant is quite difficult. In some cases overruns are recognized as write downs for the developer and not as costs associated to a generation project. They do affect the business case of the company, but are not included in the business case of a plant.

Contingency costs may be added by the user of the modeling tool directly as an input.

2.5.4 Operation and maintenance (O&M) costs

O&M costs are costs arise during the operating phase of the plant. Operating costs accrue not only when the plant is generating electricity, but also when it is ready to start operation at some point in the future[47]. Investors and operators usually distinguish two main types of O&M costs:

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[45] No specific breakdown for hydropower owner's costs. All owner's cost are included in owner's cost 1. Source: interviews, plants surveys and PRYSMA analysis. Example for Germany: CCGT 400 MW, coal 400 MW, hydropower 150 MW, off-shore wind 150 MW, on-shore wind 50 MW and solar PV 10 MW.

[46] Nuclear plants, not included in the scope of RE-COST, tend to incur many cost overruns. Contingency costs of 100% have been documented in some of them. The nuclear plants being built now are expected to incur even further cost overruns due to design changes after the Fukushima Daiichi nuclear incident.

[47] Even plants that have been mothballed generate operating costs, for instance, security, rent, etc.

- **Fixed O&M costs** usually include the fixed maintenance of the plant (power train or turbine maintenance agreement, facilities maintenance, etc.), plus the costs associated to the maintenance and operation staff, including administrative staff.

- **Variable O&M costs.** The definition of these costs is much wider, and depending on the source, different items may be included. Strictly speaking, variable generation costs would include any cost incurred by the fact that the plant is running and generating electricity: fuel costs, insurance costs, emission rights, variable maintenance, etc. However, many investment models and simulations consider fuel, insurance and emissions costs as separate items. This facilitates the evaluation of their impact on the costs of generation.

Operators keep detailed records of the O&M costs associated to each generation unit within a plant. However, investment decisions are usually based on averages calculated bottom-up (using actual results from operations), or top-down (using averages or benchmarks). As the number of plants in operation increases, the detail and accuracy of data, and the understanding of the drivers of O&M costs are increasing. However, data in the public realm still show significant variability and degree of uncertainty due to a number of reasons:

- The information on operation and maintenance costs is considered as especially sensitive by manufacturers and developers. These stakeholders do not disclose accurate and detailed maintenance costs in the public realm.

- Some data of new plants and projects are theoretical because they have not had the opportunity to incur into significant O&M costs.

- In some cases, maintenance is or will be provided by a third party supplier through an annual fee that does not detail cost components.

Figure 21 displays examples of fixed and variable levelized O&M costs from the simulation model, at different utilization levels.

Cost / Technology *(size and utilization)*	**ON Wind *(50-100MW 35%)***	**OFF Wind *(150 MW 45%)***	**Solar PV *(8 MW 25%)***	**Hydro *(50 MW 45%)***	**CCGT *(400 MW 75%)***	**Coal *(400 MW 60%)***
Fixed O&M	4.5 - 7.2	10.2 – 21.9	17.6 – 51.7	1.9 – 17.0	1.6 – 5.8	4.0 – 8.3
Variable O&M	7.6 – 22.7	17.4 – 29.0	≈0 (small)	1.4 – 15.0	2.5 – 3.4	1.8 – 3.8

Figure 21: Examples – Operating and maintenance costs (US$/MWh) – Averages [48]

Approach to modeling O&M costs: Specific O&M data for some of the plants included in the database was obtained in the data collection process. The modeling tool computes O&M costs as a function of the technology, region, and capacity factor of the plant under consideration. The large ranges in O&M costs are due to how they are recognized by different investors, and to differences in the O&M contracts established by them.

2.5.5 Fuel costs

Fuel costs are variable operating costs of coal-fired and gas-fired plants. Fuel costs represent a significant part of the costs of generation of some of the technologies in the scope of the study. In particular, the costs of gas is one

[48] Hydro data comes from publications. The rest of the data are results of analyses from data gathered in the framework of the RE-COST Study.

of the primary, if not the most important, factor that determines the business case of gas-fired plants. Therefore, investors devote considerable time and effort to assessing fuel costs, and to gauge how their variations may influence the future cost of generation of a plant. The next figures display simulations of levelized costs showing the proportion that the cost of fuel represents in gas-fired and coal-fired plants.

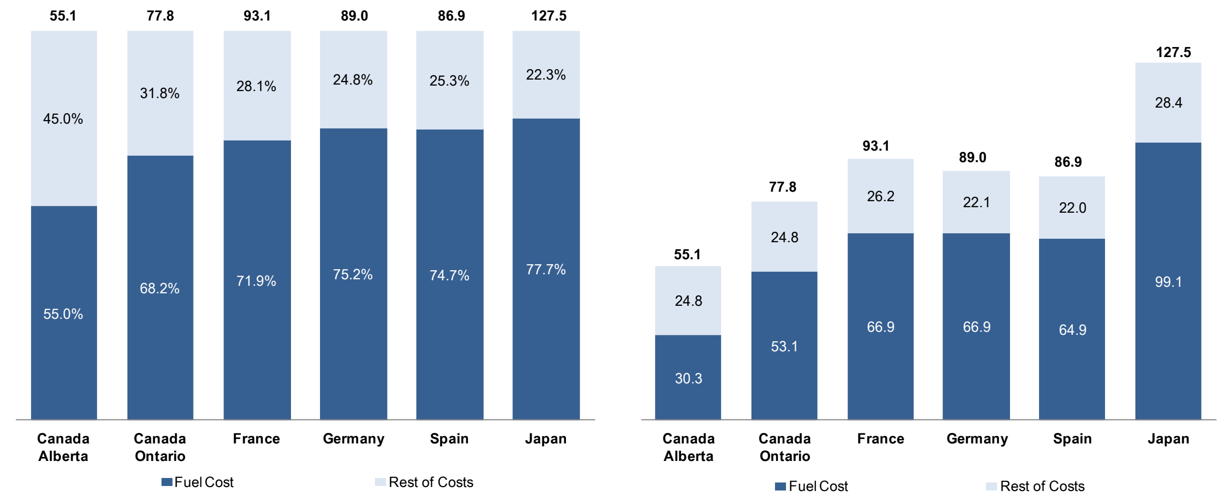

Figure 22. Gas-fired – Impact of fuel cost over LCOE (%, US$/MWh)[49]

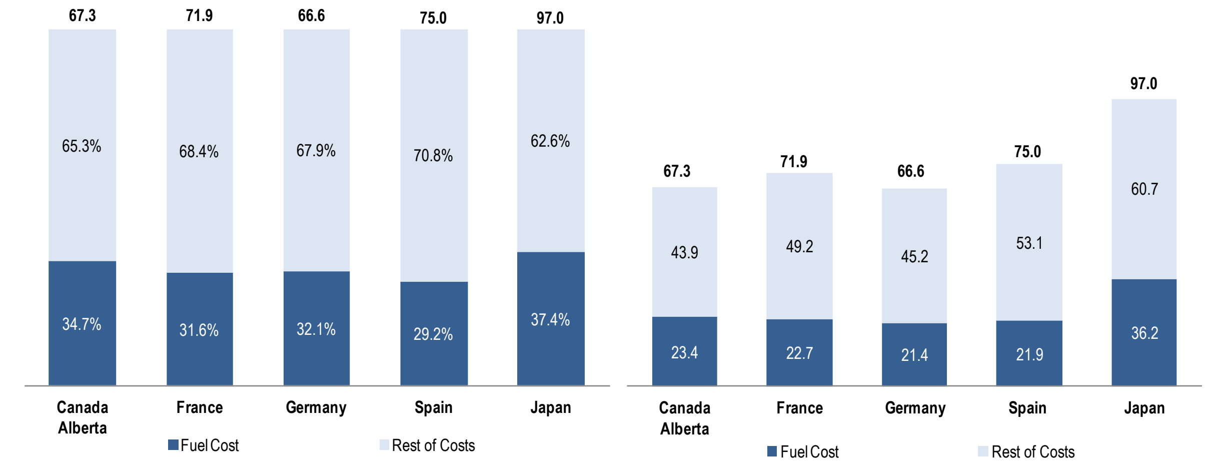

Figure 23. Coal-fired – Impact of fuel cost over LCOE (%, US$/MWh)[50]

The evolution of fuel prices over the life of a generation plant will depend on the interplay of supply and demand in a given region/country, and of the specific contractual provisions established between providers and buyers. Figure 24 shows the price history of gas during the last five years in the New York Mercantil Exchange (NYMEX).

[49] Technical average case. Discount rate 5%

[50] Technical average case. Discount rate 5%

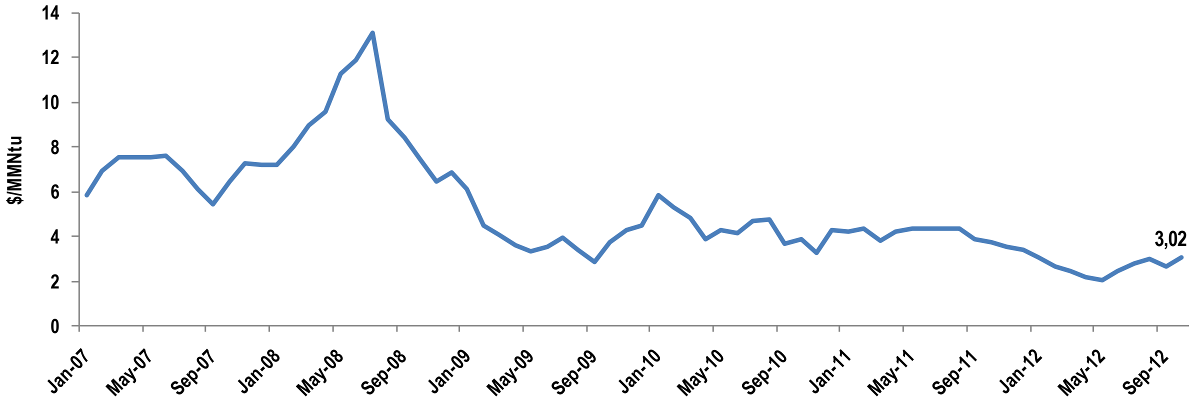

Figure 24. Natural gas contracts settlements price history (US$/MMBtu)[51]

Forecasting fuel costs in the short term, is relatively straightfoward. Data from the Futures Markets can be used to assess different growth scenarios. Forecasting fuel prices for the long term is much more difficult. Figure 25 shows an estimate of gas prices used by one official agency to define their long term development plant for RET 2012-2030. The potential variation of gas prices is in the range of +25%/-5%. Projections from other sources show similarly wide variations in their forecasts.

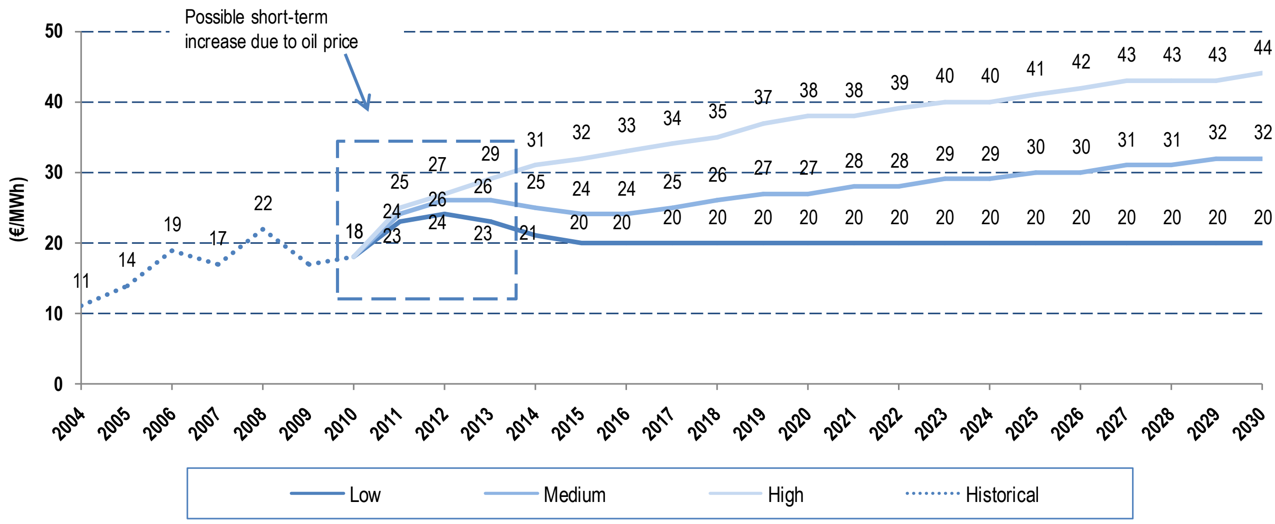

Figure 25. Example of gas cost forecast (€/MWh) – Three potential scenarios – 2010[52]

[51] Source: New York Mercantile Exchange (NYMEX) – Natural Gas Contract Settlement Price History

[52] Source: IDAE (Instituto para la Diversificacion y Ahorro de Energía (Spain) – PER 2011-2020

RE-COST approach to modeling fuel costs: An extensive number of simulations has been conducted to gauge the impact of fuel prices over the costs of generation of each relevant region/technology pair in the scope of the study (see Section 5). The following table shows the ranges of prices that have been used to determine initial fuel costs.

Fuel Cost	Canada	France	Germany	Spain	Japan	IEA Europe[53]
Gas (US$/MMBtu)[54]	3.9–8.9	9.6–12.8	9.6–15.0	10.1–10.6	12.8–14.7	10.3–11.7
Coal (US$/MMBtu)[55]	1.3–3.1	2.2–6.6	2.2–4.4	2.2–4.3	3.5–4.9	3.24

Figure 26. Fuel costs (US$/MMBtu)

2.5.6 Insurance costs

Plants have to insure against a number of potential incidents by law. In addition, insurance reduces the risks associated to technical setbacks, or to other sources of uncertainty and variation in the operation of a plant.

The prices paid for insurance depend on many factors. One of the most important is the perception of risk of each technology. In the last few years, insurance costs for all types of generation plants have significantly increased. But other factors are also contributing to raise the costs of insurance, such as the need to insure against business contingencies, or to cover for the costs incurred by a project that is stopped or delayed[56].

RE-COST approach to modeling insurance costs: The model adds insurance costs as a ratio of capital cost. The initial data used are average insurance costs obtained from interviews and desk-top research (indicative only):

- The data available represent a small fraction of the installed power in each country.
- Insurance prices depend on many factors unrelated to the characteristics of the project, as spelled out by very specific bilateral contracts between the contracting parties.

	On-shore wind	Off-shore wind	Solar PV	Hydro	CCGT	Coal
Insurance (% Capital Cost)	0.72%	0.71%	0.6%	0.6%	0.76%	0.69%

Figure 27. Insurance costs – Examples of average insurance costs in the RE-COST database[57]

2.5.7 Cost of emission rights

Emission rights also influence investor's decisions. Currently, a number of policy schemes attempt to make polluters pay for the emissions they produce, and to compensate clean sources of energy for the emissions they

[53] Source: Projected Costs of Generating Electricity. IEA

[54] Source: Canada: Industrial Prices. "Statistics Canada. Energy Statistics Handbook". Ministry of Energy (Ontario), Ministry of Energy (Alberta) and Ministère des ressources naturelles et de la faune (Quebec).France, Germany, Spain and Nordic: minimum: "World LNG estimated November 2012 landed prices. Federal energy regulatory commission". Maximum: Industrial prices. "Eurostat. 2011". Japan. Minimum: "LNG estimated November 2012 landed prices. Federal energy regulatory commission". Maximum: "BP Statistical Review of World Energy"

[55] Source: Canada: Data from interviews. France, Germany, Spain and Nordic: data from European utilities. Japan: Minimum "BP Statistical Review of World Energy". Maximum: data from interviews

[56] *No renewable energy approvals for offshore have been issued and no offshore projects will proceed at this time. Applications for offshore wind projects in the Feed-In-Tariff program will no longer be accepted and current applications will be suspended*. Ontario Ministry of the Environment. February 11th, 2011

[57] Source: UK Electricity Generation Costs Update – Matt MacDonald

avoid. For instance, the third phase (2013-2020) of the EU ETS defines a cap-and-trade scheme handling allowances. From 2013 there will be only one single cap (number of allowances) for the entire EU, which will be allocated either for free (an allowance) or through auctions. Power producers who enter full auctioning will be able to pass the cost associated to emissions to their customers. Industrial installations will be shifted gradually into full auctioning by 2027[58].

The costs of emissions depend on the quantity of emissions produced and on the prices associated to these emissions. The amount of emissions is a function of the type and quantity of the fuel used. A number of factors influence this ratio:

Generation technology: Coal, and gas based technologies generate different amount of emissions by unit of generated power. The next figure shows average emissions of coal and natural gas in the OECD and their evolution over time.

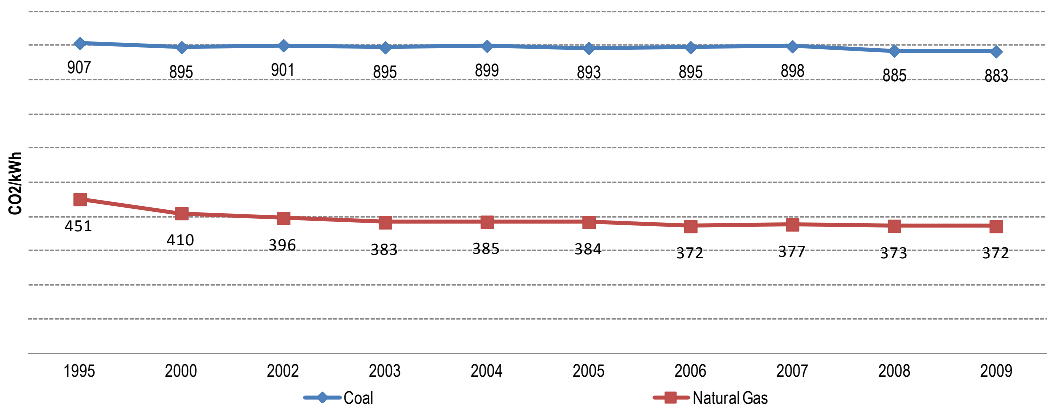

Figure 28. OECD average emission rates – Evolution[59]

Fuel characteristics: The provenance and composition of the coal used in a plant may have a significant impact on the type and quantity of emissions produced per unit of generated power. The table below shows some differences in amounts of CO_2 equivalent emissions depending on the type of fuel used.

Natural gas – CO_2 emissions per kWh	2005	2006	2007	2008	2009	2010	Ranges used
Canada	446	436	449	489	460	499	436 – 499
France	264	314	318	322	463	520	264 – 520
Germany	309	298	299	315	311	346	298 – 346
Norway	302	301	341	312	302	343	301 – 343
Sweden	218	219	215	216	209	209	209 – 219
Spain	319	356	339	349	353	358	319 – 358
Japan	441	443	445	442	438	430	430 – 445

Figure 29. Natural gas – CO_2 emission rates per country from electricity and heat generation (gram/kWh)[60]

[58] *The number of allowances will be defined in such a way that there will be a linear 1.74 reduction in the number of allowances each year compared to the annual average of the 2008-2012 allocations, adjusted to take account of e.g. the wider scope as from 2013. (Directive 2009/29/EC)*

[59] Source: CO_2 emissions from fuel combustion Highlights (2012 Edition). IEA. Includes the corrections issued in 2013.

[60] Source: CO_2 emissions from fuel combustion Highlights (2012 Edition). IEA. Includes the corrections issued in 2013. CO_2 emissions from coal and peat consumed for electricity generation, in both electricity-only and combined heat and power (CHP) plants, divided by output of electricity generated from coal. Both main activity producers and autoproducers have been included in the calculation.

Coal – CO_2 emissions per kWh	2005	2006	2007	2008	2009	2010	Ranges used
Canada	898	921	851	812	928	923	812 – 928
France	966	1,003	1,012	1,036	1,048	949	949 – 1,048
Germany	867	904	907	896	906	889	867 – 907
Spain	886	901	943	901	926	937	886 – 943
Japan	911	917	916	906	909	902	902 – 917

Figure 30. Coal/peat – CO_2 emission rates per country from electricity and heat generation (gram/kWh)[61]

Characteristics of the plant: including plant size, work rate, efficiency, emission control mechanisms used (e.g., Carbon Capture and Storage – CCS – technologies used to store waste CO_2), etc.

Emission prices: Forecasting the price of CO_2 equivalent emissions may be difficult, given the scarce definition of scenarios and global emission reductions targets, as well as the challenges that CO_2 markets have experienced in the last years. The next graph shows an example of CO_2 price forecasts used by a state agency in Spain, depicting the high levels of uncertainty associated with the future prices of emissions, and the large chance of errors – today (2013), prices of emmissions are at 3-4US$/t.

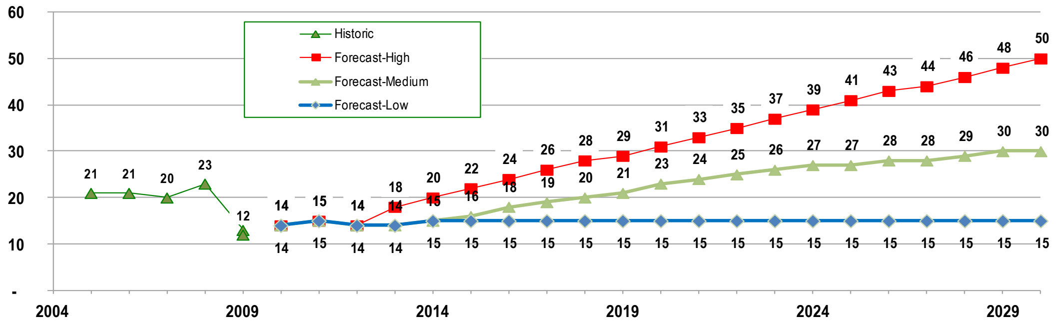

Figure 31. Example of forecast price of CO_2 (€/t)[62]

Figure 32 displays the results of cost simulations (LCOE), showing the proportion that emission costs would represent for an average price of emissions of 10 US$/t CO_2[63] for gas and coal-fired generation. However, at the present, excess allowances have significantly reduced the prices of emissions for most European plants to figures below 4 US$/t CO_2. This contributes to reduce the costs of generation of coal-fired plants, making their business cases more attractive.

[61] Source: CO_2 emissions from fuel combustion Highlights (2012 Edition). Includes the corrections issued in 2013. CO_2 emissions from coal and peat consumed for electricity generation, in both electricity-only and combined heat and power (CHP) plants, divided by output of electricity generated from coal. Both main activity producers and autoproducers have been included in the calculation.

[62] Source: Spain 2011-2015 Renewable Energy Plan (PER) – IDAE. Using 2010 as a baseline.

[63] The model has been run with a range of potential emission prices to determine the impact of this cost factor in the decisions of investors. However, significant uncertainty exist as of the potential prices that emissions may reach in the medium and long terms.

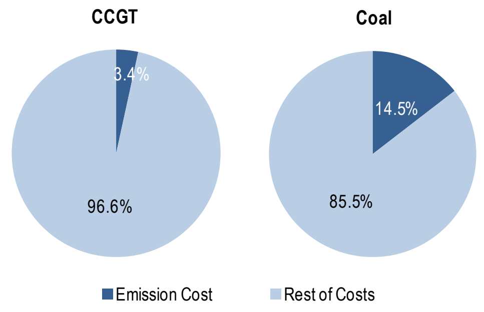

Figure 32. Example – Impact of emission cost for gas and coal over LCOE (%, US$/MWh) – Germany

RE-COST Approach to modeling emissions costs: The simulations conducted have used data from the Climate Economies Chair as reference prices in the EU region. 12.0-24.0 €/tCO_2 (15.6-31.2 US$/t$CO_2$) in 2020 [64] and 3-10 US$/t$CO_2$ today.

To reflect the uncertainty associated with the future costs of emissions, *"what-if?"* analyses have been conducted. This has enabled to gauge the impact of variations in emission prices over the potential business cases of gas- and coal-fired plants.

2.5.8 Transmission costs

Transmission costs consist of the fee the producer has to pay to transmit the electricity produced[65]. The size of this cost depends on a large number of factors: (1) the amount of electricity fed into the grid; (2) the characteristics of the plant under consideration, and its operating regime, such as load, utilization, and location; and (3) regulatory elements. The treatment of these expenses and the proportion that is allocated to the producer considerably vary in the different countries included in the study. For example, in Quebec, Hydro Quebec has considered balancing and transmission costs to calculate the prices paid to on-shore wind plants.

Accurately forecasting transmission costs for the life of a project (20-50 years) is not feasible. Approximations must be conducted. Some investors perform bottom-up analyses of the transmission costs potentially assessed to their generation projects (large utilities), using different factors. Many calculate average transmission costs, and add them to the generation costs of their projects.

RE-COST approach to modeling transmission costs: The analysis tools used in this study approximate transmission costs using averages obtained from publications and from the data associated to the database of plants and projects. This way of evaluating transmission costs is useful to provide general insights about the region/technology pairs included in the scope, but is not valid to assess the specific transmission costs associated to a given plant.

If the business case of a specific plant needs to be assessed, transmission costs must be calculated with a separate tool, and directly added to the simulated cost of each plant or project as an additional cost.

	Canada	France	Germany	Norway	Sweden	Spain	Japan
Transmission Cost	5-17	4-14	3-16	4-17	3-10	10-14	10-20

Figure 33. Example – Assessment of transmission costs (US$/MWh) – Ranges[66]

[64] Simulations of EU ETS conducted with the ZEPHYR-Flex model, developed by the Climate Economics Chair.

[65] In this report, transmission costs do not include the one-time costs associated to connecting a new plant to the existing grid, and reinforcing the grid to assume the load of the new plant. These costs, that may be considerable in some projects located far away from the built grid, or for large plants (coal-fired, for instance), or for some off-shore developments, have been considered under the chapter *Owner Costs*, in Section 2.5.2, following the lifecycle philosophy utilized to evaluate plant costs.

[66] Source: Europe: "Overview of transmission tariffs in Europe Synthesis 2012. ENTSO-E". Canada: Hydro-Québec call for tenders. Japan: estimated value through interviews.

Other grid costs are also worth discussing **even if they do not affect the business case of a plant.** RET with variable or intermittent generation patterns, such as wind and solar PV, may generate a number of additional costs to the electric system[67], examples include:

- The day to day cost of balancing scheduled and unscheduled variations in the output of the plant.
- Investments in additional installed capacity to cover peak demand when the intermittent sources cannot do it.
- Investments in reinforcements of transmission and control systems in the grid, which are borne by the TSO.

A number of studies have begun to quantify the costs incurred by the system due to variability or intermittency. But figures in the public realm are still few and display large variations.

Investors do not factor in the costs associated to transmitting electricity in their calculations, unless they have to pay for them. But these costs may be very relevant to policy makers that have to decide how to incentivize variable RET or large non-RET generation plants. While the proportion of variable generation is small, highly dispatchable technologies, such as gas-fired plants, may balance the load of the system. However, when the generation mix of a country includes high proportions of intermittent generation, it is necessary to incur additional costs to ensure balancing. Accurately computing these costs and defining who has to pay for them are key issues for policy makers.

2.5.9 Decommissioning costs

Decommissioning consist of dismantling a plant at the end of its life-cycle. Dismantling involves operational and administrative tasks. Some of them are legally required by local rules and regulations. Decommissioning a plant based on a technology other than nuclear poses similar problems to those faced by other industrial enterprises. It is necessary to return the land to a specified condition; removal or cleaning of environmentally damaging materials must be ensured; and materials and components have to be scrapped or reused.

The main challenge in the evaluation of decommissioning costs is the large number of factors that influence them (location, local regulations, existing supply chain, etc.). Investors use very different approaches to evaluate these costs. In some cases, they have direct experience in the decommissioning of a plant. In other cases, they request a quote from specialized companies.

Figure 34 shows the ranges of impact of decommissioning in OECD countries costs for the technologies in scope.

(US$/MWh)	On-shore wind	Off-shore wind	Solar PV	Hydro	CCGT	Coal
Decommissioning Costs	0.16-1.15	0.29-1.32	0.04-4.67	0.03-0.67	0.02-0.18	0.01-0.18

Figure 34. Example of impact of decommissioning costs (US$/MWh)[68]

[67] Source: Projected costs of generating electricity – 2010 edition IEA

[68] Projected costs of generation of electricity (2010 Edition) – IEA, NEA.

RE-COST approach to modeling decommissioning costs. Decomissioning costs are calculated for each of the technologies in the scope of the report. Excluded from the calculations are:

- Repowering (replacing less efficient turbines with more efficient ones) in the case of wind farms.
- Blade replacement and recycling. An event that happens during the operating life of a wind farm, and that at this point does not have an easy solution because recycling blades is rather difficult and costly.
- Second hand market for gas turbines – It provides the possibility to add a residual (negative) cost at the end of the economic life of a plant, thus modifying total levelized costs.

2.5.10 Financing costs – Interest rates

Finance rates for generation projects depend on a host of factors. Investors devote significant time and effort to ensure they attain the most advantageous conditions for their projects, (see Section 2.4).

Approach to modeling financing costs: The rate ranges used to model the business case of generation are summarized in the table below. **These values should not be taken as evidence of averages of rates in the countries under consideration, but as ranges used in the simulations.**

Discount Rate		Canada-Alberta	Canada-Ontario	Canada-Quebec	France	Germany	Norway	Sweden	Spain	Japan
On-shore wind	Equity	15%	8%	8%	10%	10%	11%	11%	12%	8%
	Debt	3%	3%	3%	3%	3%	5%	5%	6%	3%
Off-shore wind	Equity				12%	12%	13%	13%		11%
	Debt				6%	6%	6%	6%		5%
Solar PV	Equity		10%		10%	10%			12%	8%
	Debt		3%		3%	3%			6%	3%
Hydro	Equity		8%	8%		10%	11%			6%
	Debt		3%	3%		3%	5%			3%
CCGT	Equity	10%	11%		13%	13%			15%	6%
	Debt	3%	3%		4%	4%			8%	3%
Coal	Equity	11%			13%	13%			15%	6%
	Debt	3%			4%	4%			8%	3%

Figure 35. Examples of ranges of discount rate per technology and country (%)

Two mechanisms were used to approximate ranges of financing rates for each of the region/technology pairs included in the study:

- **Data collection.** Data from some plants and projects included details about the specific scheme used to finance them, and the financing rates used (very few).
- **Discussions and workshops** with experts and investors, who provided their views about the financing rates and schemes which might be applicable in each region/technology pair.

Examples of factors that influence the financing rates in each pair region /technology include:

- Different perception of risk between renewable and non-renewable technologies. In some cases the first receive incentives, and the latter are primarily subject to market prices.
- The risk perception of renewable technologies varies depending on the type of support: PPAs have lower discount rates than FITs, which have lower discount rates than other types of support like green certificates or offsets.
- Conventional technologies like CCGT and coal show higher discount rates in the current situation than those expected in the past, due to actual lower capacity factors that reduce the attractiveness of the business case for investors.
- Off-shore wind shows higher financing rates than on-shore wind due to the risks associated with this technology.

- Differences between Canadian regions are due to the different compensation systems for renewable technologies used in each region in the scope of analysis.
- The current economic situation in Spain, and the uncertainty associated with the future electricity policies in this country increases financing rates of all generation technologies.
- Norway and Sweden show slightly higher financing rates than France or Germany due to currency risk.
- The recent measures taken by the government to support non-nuclear energies after the Fukushima accident contribute to decrease financing rates in Japan for RET generation.

2.5.11 Cost sensitivity to different factors

Costs of generation are very sensitive to the variations of a large number of factors. Investors consider the potential variations of factors costs, and assess their impact on generation costs. This enables them to gauge the reliability of their calculations, and to assess the risk of the project. A project where factor costs are likely to have large variations will result in large potential variation of final costs, adding risk to investors.

Figure 36 shows examples of the sensitivity of costs of different technologies to different cost factors. The longer the horizontal bars, the higher the impact that the variation of the cost driver has on the costs of generation.

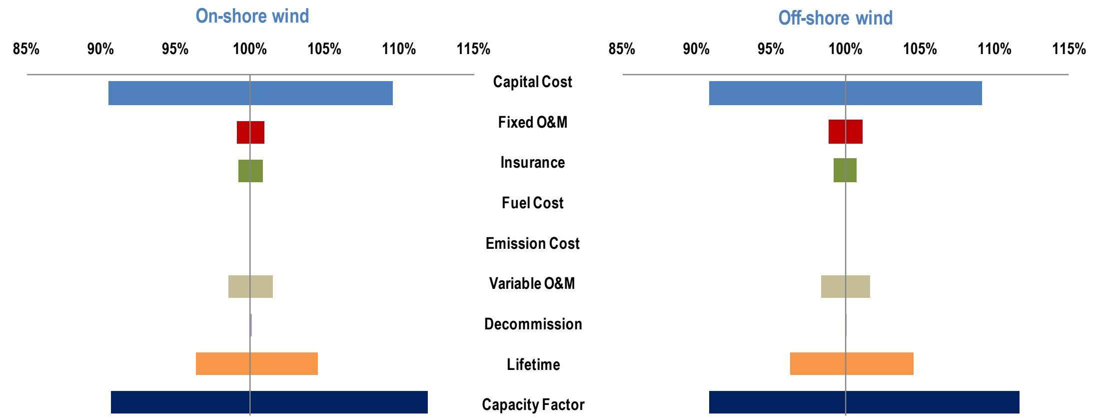

Figure 36. Example – Sensitivity analysis – On-shore wind and Off-shore wind [69]

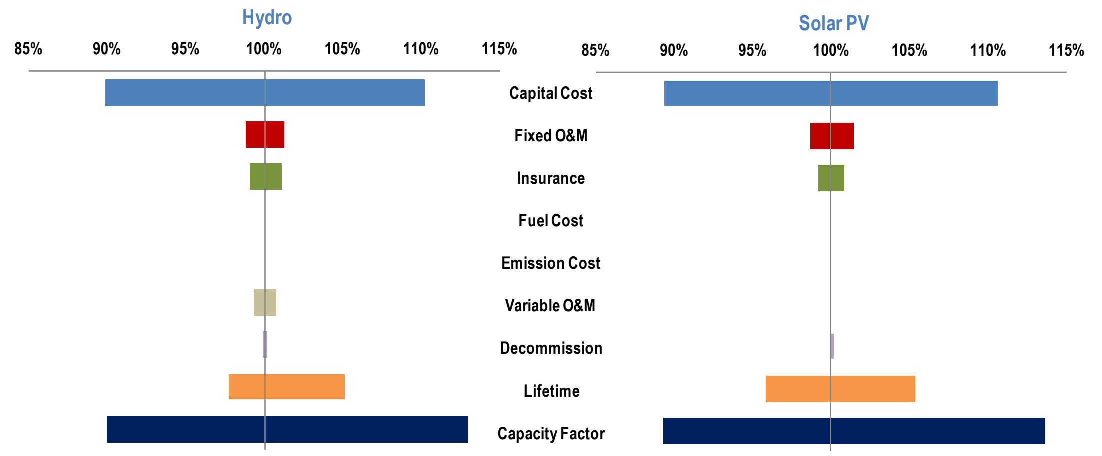

Figure 37. Example – Sensitivity analysis – Hydro and solar PV [70]

[69] LCOE with a 12% variation of each parameter from the average case. [On-shore wind: 50 MW, 5% discount rate (DR), 30% capacity factor and 20 years lifetime; Off-shore wind: 150 MW, 5% DR, 40% capacity factor and 20 years lifetime]

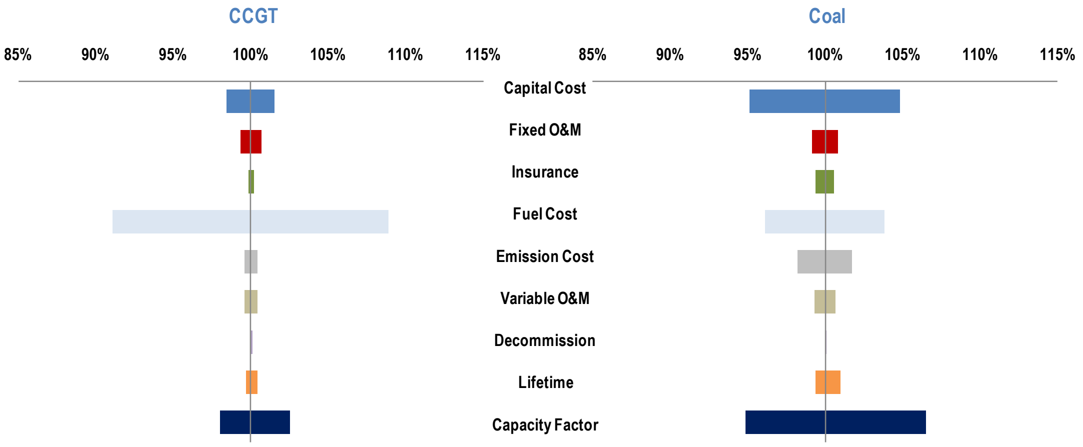

Figure 38. Example – Sensitivity analysis – CCGT and coal [71]

2.6 Assessment of generation revenue

Revenues from the electricity generated depend on three components (1) the quantity of electricity produced, (2) the price of electricity, and (3) additional sources of revenue.

$$Rev_t = \ Elec_t \ x \ Elec_{price} + \ Elec_{addtl.}$$

$$Rev_t = \ Revenue \ in \ year \ t$$
$$Elec_t = Electricity \ produced \ in \ year \ t$$
$$Elec_{price} = The \ variable \ price \ of \ electricity$$
$$Elec_{taddtl.} = Additional \ sources \ of \ revenue \ in \ year \ t$$

Figure 39. Revenue from electricity and other sales

Investors use a variety of tools to assess future revenues. Utilities and companies specialized in funding the electricity sector, use dynamic revenue models, which consider a large number of variables, including competitive situations; macro-economic variables (electricity demand, and trends); type of contract – spot / by contract markets; imports and exports in addition to energy from local plants; etc. Smaller, less specialized investors, may use educated approximations to forecasting revenues with more or less level of detail.

2.6.1 Electricity produced

The amount of electricity produced by a plant is a function of its size, capacity factor (or utilization), and the expected life of the plant. Investors make hypotheses about the average values and ranges of variation of these parameters to compute the output of the plant. Utilities use large, complex models that calculate potential plant utilization as an output of market demand and supply, the evolving characteristics of the generation environment (other plants, policies, evolving costs, etc.), and many other factors. Other investors compute the impact of a

[70] LCOE with a 12% variation of each parameter from the average case. [Hydro: 50 MW, 5% DR, 45% capacity factor and 30 years lifetime; Solar PV: 8 MW, 5% DR, 25% capacity factor and 20 years lifetime]

[71] LCOE with a 12% variation of each parameter from the average case. [CCGT: 400 MW, 5% discount rate, 75% capacity factor and 30 years lifetime; Coal: 400 MW, 5% DR, 60% capacity factor and 40 years lifetime]

handful of key factors, for instance, the expected life of the project, average capacity factor, average losses, etc., and assess the level of risk associated to the proposed investment through less sophisticated models.

Capacity factor (or utilization) *is the ratio between the actual power generated and the maximum power that the plant could generate. This indicator measures the percentage of installed capacity that is utilized*[72]. The potential capacity factor of a plant over its lifetime is a critical input in the calculation of its financial results. Once the capital outlays of the plant have been made, it is imperative to ensure a utilization rate that maximizes the returns to investors. The impact of capacity factor on average or levelized cost of electricity (LCOE) is very significant, as shown by the sensitivity analyses depicted in Figure 40 and Figure 41.

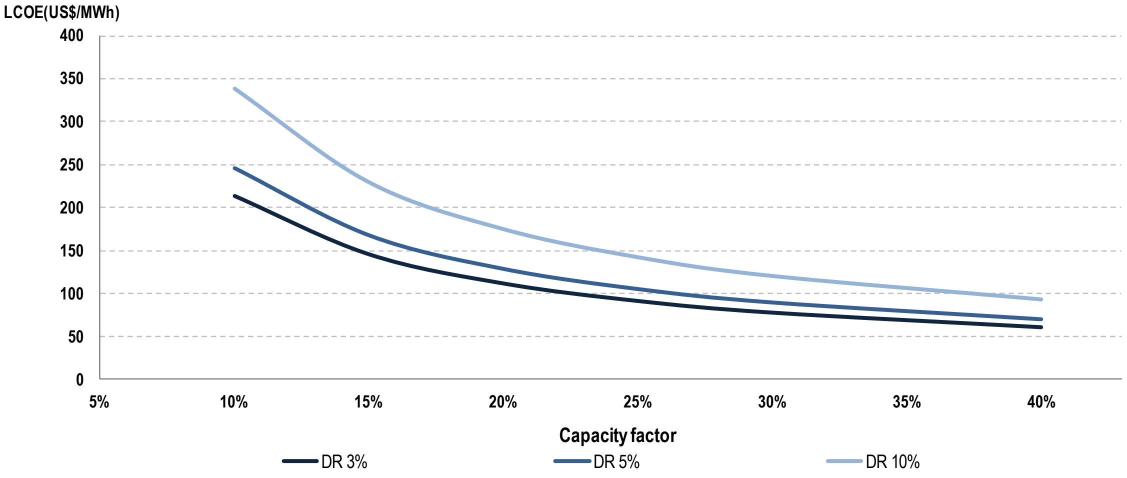

Figure 40. Example – LCOE sensitivity to capacity factors and discount rates (Germany / On-shore wind)[73]

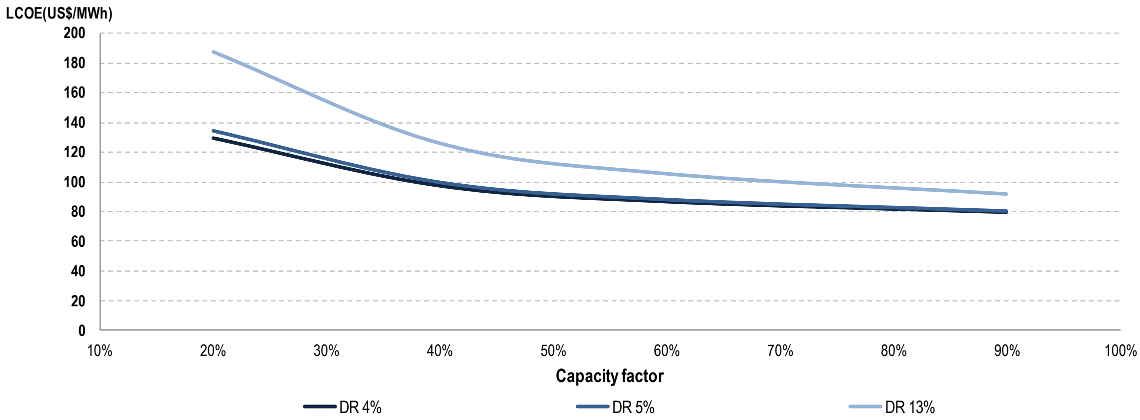

Figure 41. Example – LCOE sensitivity to capacity factors and discount rates (France /CCGT)[74]

Figure 42 displays examples of standard or technical operating factors per technology. They represent averages from data obtained in industry interviews and from publications. They are reference values, not the values at which any specific plant will operate.

[72] Source: Monitoring Performance of Electric Utilities. The World Bank, 2009

[73] Based on simulations of 50 MW plant, with construction time equal to 2 years, and 20 years of economic life.

[74] Based on simulations of a 400 MW plant, with construction time equal to 2 years, and 30 years of economic life.

	On-shore wind	Off-shore wind	Solar PV	Hydro	CCGT	Coal
Capacity factor	30%	40%	20%	45%	75%	60%
Lifetime (years)	20	20	20	30	30	40

Figure 42. Design capacity factors and lifetimes by technology

The actual capacity factors at which a plant operates may be very different from the values depicted in Figure 42, due to a number of reasons:

- **The situation of the economy of the region/country where the plant operates,** which directly affects electricity demand. Power consumption has a large impact in the average capacity factors of the generation plants participating in the market of a given region; in particular if they enter last in the merit-order curve.
- **Weather patterns.** Weather influences capacity factors in a number of ways: Unseasonal cold and heat increase consumption of electricity. This in turn increases the average capacity factors of the plants operating in a region (the impact may be local, national, or international). Dry conditions reduce the output of hydro plants (lower capacity factors). The Nordic countries and Quebec are particularly affected by this factor, due to the importance of hydro in their generation mix. Wind farms can operate only under certain conditions. Intense or very low wind speeds reduce the utilization.
- **Changes in the portfolio mix of a region:** The phasing out of nuclear plants in Germany is resulting in large changes in the average capacity factors of plants based on other generation technologies. Something similar has happened in Japan in 2012. The reduction in output of a given technology has to be covered by output increases of other technologies to match demand.
- **Place in the merit-order-curve:** Some plants that were expected to operate as base load – for instance CCGT and coal – are being used now as peak capacity. They enter later than RET in the market merit-order-curve. As a consequence, some CCGT plants that were designed for average capacity factors of 75% are operating at 30% or less.

Figure 43 shows average plant capacity factors by region/country in different reference years, calculated as the ratio between the actual electricity generated in the region by a given technology, divided by the potential electricity that could have been generated by the total installed capacity in the region.

Country - Technology	Alberta (2010)	Ontario (2010)	Quebec (2010)	France (2011)	Germany (2011)	Norway (2011)	Sweden (2011)	Spain (2011)	Japan (2011)
Wind - on-shore	30%	24%	33%	20%	18%	29%	24%	23%	23%
Wind - off-shore				**	20%***	**	30%***		25%***
Solar PV		16%		9%	8%			20%	~0%
Hydro	24%	44%	53%	23%	55%*	46%	47%	19%	22%
CCGT	64%	27%		36%	37%	52%	24%	23%	56%
Coal	64%			19%	60%			43%	56%
Nuclear		78%	60%	76%	99%		71%	85%	24%

Does not exist in the country or irrelevant

* Hydro in Germany includes biomass

** In 2011 offshore wind plants were still under viability analysis or in draft form

*** Capacities are estimations – There is no breakdown between on-shore and off-shore wind generation

Figure 43. Proxies for capacity factors of technologies in each country – 2011[75]

[75] The proxies are approximations to the average capacity in a region. A given plant may have higher or lower rates of capacity than those stated in this table

RE-COST approach to modeling plant capacity. The impact of plant capacity factors has been evaluated in each of the region/technology pairs in the scope. Design rates (as depicted in Figure 42), and proxies for capacity factors (as shown in Figure 43) have been used as references only, not as the actual values of the capacity factor of a given plant in the database.

Extensive sensitivity analyses have been conducted to quantify and display the impact of this parameter in the business case of each region/technology pair as discussed in Section 5.

2.6.2 Electricity generation price

Accurately assessing the prices that will be paid for the electricity generated during the lifetime of a plant is impracticable. There are too many variables that will influence prices over an extended period of time. Investors and other actors use ranges of prices to simulate the potential future revenues of a generation project. Price ranges are obtained from different sources:

- Internal information – based on historical prices and forecast.
- Publicly available information, gathered from different sources such as expert reports.
- Prices quoted in the electricity markets relevant for each generation project (e.g. the price of the pool).
- Others.

Figure 44 shows examples of prices in different electricity markets. The prices of interest for this study are the prices paid to the power producers, not the retail prices of electricity.

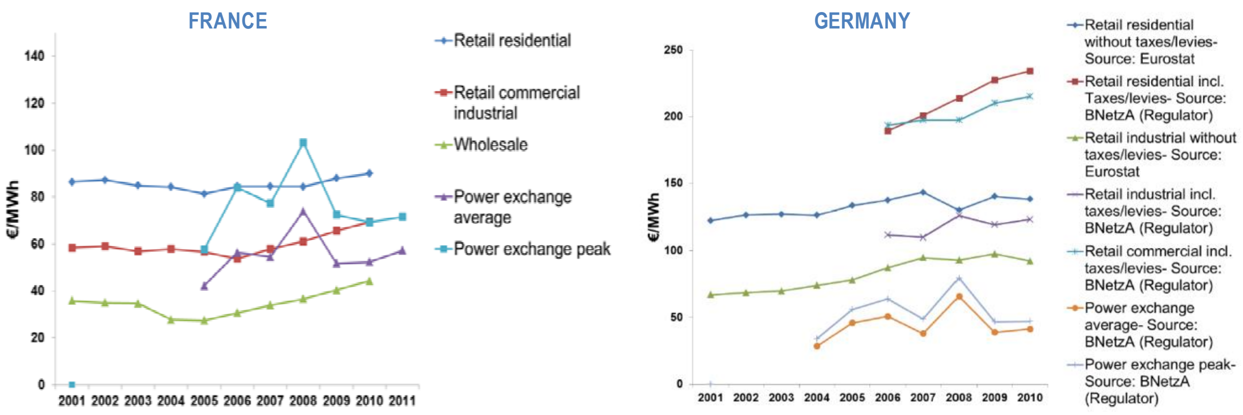

Figure 44. Evolution of French[76] and German[77] electricity prices (2001-2011)

The power exchange prices constitute a good initial reference to compute the business case of an electricity generation project. Every investor is well aware of the price levels and their trends in their target markets. However, the actual prices received may be quite different from the published prices in power exchanges due to a number of reasons:

- **There is no power exchange**. This is the case of Quebec, where most of the electricity consumed is purchased from Hydro Quebec Distribution.

[76] Source: Data from EdF-EN, displayed in electricity prices scenarios until 2020 in selected EU countries – PV parity Project" – Jan. 2012

[77] Ibid

- **The relevance of the power exchange is small**. For example, the spot prices of electricity in Japan are not a fair proxy for the prices paid to producers because the spot market is very small. Another example is Ontario, that has a power exchange, but where the prices of generation are determined through contracts between producers and the Ontario Power Authority, which ensures a price to the producers that is usually higher than the price of the spot market.

- **Electricity may be purchased directly from suppliers through bilateral contracts** whose provisions are not made public. The EU, directive 2003/54/EC allows European users to freely choose their power supplier (producers, electricity service companies, and others). In Japan, the compensation for electricity production may be in the form of transfer prices within EPCOs, or through OTC contracts between producers and consumers.

The ranges of prices used in this study for 2011 are shown in Figure 45. The boundaries of the ranges of prices are constituted by:

- The **spot prices of electricity** in the countries that have a power exchange. Both average spot prices and maximum spot prices have been considered.

- A value denominated **generation or wholesale price**. As shown in Figure 46, this price has been calculated by stripping down from the retail prices of electricity of each country the amounts associated to transmission, distribution, fees and other charges, taxes, etc. This mechanism allows computing **an approximation** of the maximum compensation that could be awarded to a generic plant; and sets up a (usually higher) boundary to simulate the business case of a generation project. The results from these calculations may vary depending on the source, and of the year used as references.

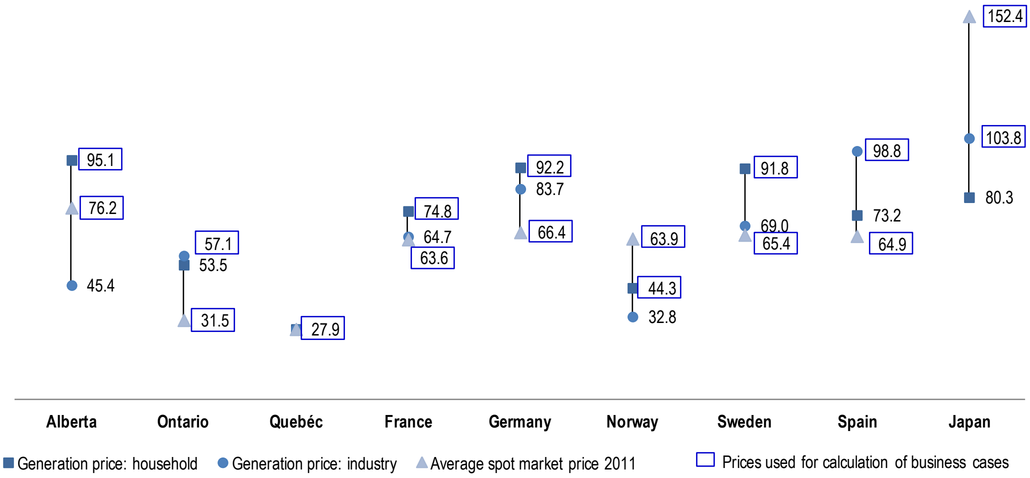

Figure 45. Reference prices (US$/MWh) per segment and country – 2011[78]

[78] Source: Base for prices 2011: Alberta, Ontario, Québec: HQ – Comparison of electricity prices 2011, France, Germany, Spain, Norway, Sweden, Japan: Key World Energy Statistics 2012. IEA

Breakdown generation price for households: Alberta – Spotpower: FACTS, Ontario – National Energy Board & HydroOne, Québec – HQ, France – MEEDDM, Germany – World Energy Council, Norway – Regieringen, Sweden – Vattenfall, Spain – UNESA, Japan – Prysma analysis according to average

Breakdown generation price for industry: based on "disaggregated price data for industrial customers 2011s2" from Eurostat

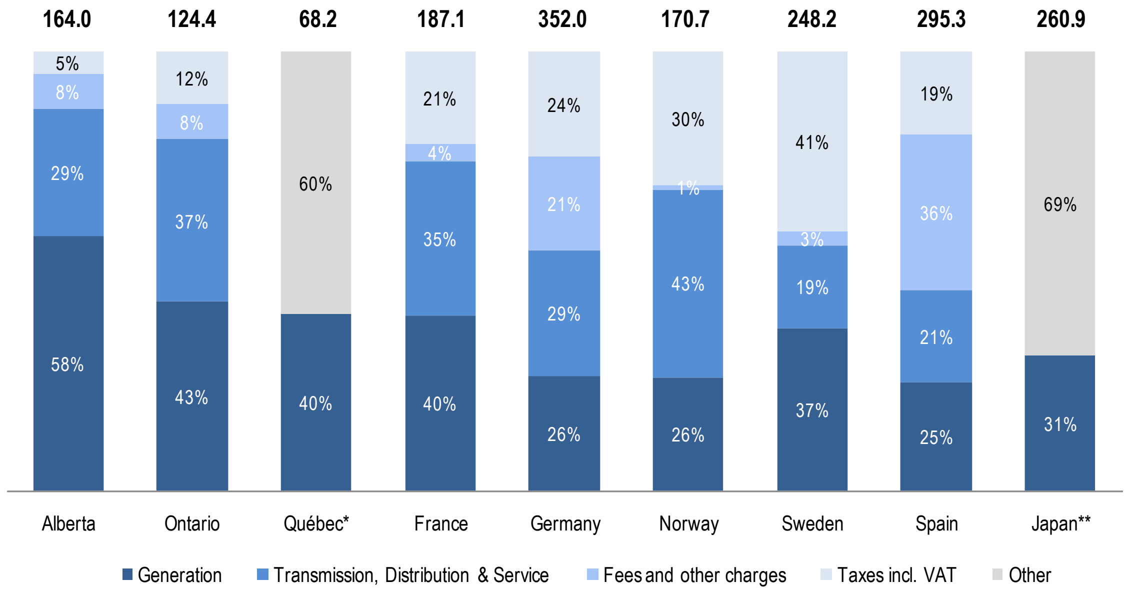

Figure 46. Breakdown of household retail prices (%,US$/MWh) per country[79]

RE-COST approach to modeling electricity prices. A large number of simulations has been conducted to identify the impact of potential prices of generation over the business case of each region/technology pair.

It is important to understand that the prices used in the simulations are only references. They permit simulating a variety of scenarios, and have proven useful to provide insights in the business cases of the region/technology pairs in the scope of this study. But they do not constitute an analysis of the effective prices that a given generation project may attain.

Unless otherwise stated, it has been assumed that market prices will grow with inflation. Or in other words, in most of the simulations conducted market prices are constant in 2012 US$.

2.7 Additional sources of revenue and costs

Investors also include in their business cases other sources of costs and revenues. In particular, policies and regulations trigger incentives and measures of support (positive or negative) to the generation of renewable and non-renewable electricity.

Investors conduct comprehensive and detailed analyses of each global, national, or local incentive that may be applicable to a generation plant, and actively lobby to ensure that their projects are eligible to receive incentives. But identifying policies in the energy sector, and quantifying its impact is not a trivial task, due to a number of factors:

- The **large number of elements** that can be considered as policies, and that result in incentives or support to electricity generation.

[79] Source: Base for prices 2011: Alberta, Ontario, Québec: HQ – Comparison of electricity prices 2011, France, Germany, Spain, Norway, Sweden, Japan: Key World Energy Statistics 2012. IEA .

*Québec: prices set by HQ, no precise breakdown available – generation cost, transmission & distribution, GST and QST

**Japan: prices are fixed by EPCOs with monopoly power in their service districts, no precise breakdown available

Breakdown generation price for households: Alberta – Spotpower: FACTS, Ontario – National Energy Board & HydroOne, Québec – HQ, France – MEEDDM, Germany – World Energy Council, Norway – Regieringen, Sweden – Vattenfall, Spain – UNESA, Japan – Prysma analysis according to average

- The **diverse means by which policy makers determine and allocate** incentives and support to the actors in the electricity sector, and to generation projects.
- The fact that in some cases the **incentives are hidden,** or reach the recipients through indirect ways.

Figure 47 shows a non-comprehensive summary of incentives to renewable generation in the countries in scope. Section 5 discusses some of the most relevant incentives in each of the regions in the scope.

	Regulatory policies			**Fiscal incentives**			**Public financing**	
	Feed-in tariff (incl. premium payments)	Electric utility quota obligation RPS	Trade REC	Capital subsidy, grant or rebate	Investment or production credits	Reduction in Sales energy, CO2, VAT, or other taxes	Public investment, land or grants	Public, competitive bidding
Canada	✓	✓		✓	✓	✓	✓	✓
France	✓		✓	✓	✓	✓	✓	✓
Germany	✓			✓	✓	✓	✓	
Norway			✓	✓	✓	✓	✓	
Sweden		✓	✓	✓	✓	✓	✓	
Spain	✓!			✓!	✓!	✓!	✓?	
Japan	✓	✓	✓	✓			✓	

✓ **Current Policies** ✓! **Applicable to existing plants, temporarily suspended or reduced for new ones**

Figure 47. Types of policies for renewable energies in the countries in scope (non comprehensive)[80]

[80] Source: REN21 Renewable 2012 Global Status Report, modified and complemented with Prysma analysis

3. THE BUSINESS CASE OF GENERATION – SUMMARY

This section presents a summary of the insights obtained from analyzing the business cases of each relevant region/technology pair included in the scope of RE-COST. Detailed results and insights are presented in Section 5, (in Part 2 of this report)

3.1 Results from cost analysis

Costs of generation are evolving due to an array of technical, market, and policy factors. These factors affect not only to new RET plants (wind and solar PV); but also to established, mature technologies. The simulations conducted in the framework of the RE-COST Study show that the costs of generation of new plants are different from the costs of generation of plants that entered operation more than 3-5 years ago (older plants).

Capital costs: The evolution of capital cost of plants is one of the key factors behind the evolution of generation costs. Figure 48 presents a comparison between the ranges of capital costs of the new plants and projects included in the RE-COST database (2009-2013), and ranges of capital costs of older plants obtained from publications and from proprietary databases (2010-2008). A number of insights emerge:

- **The capital costs associated to any technology present very wide ranges.** As discussed in Section 2.5.2, a large number of factors affect and determine capital costs. Therefore, depending on the technical and operational circumstances (for instance, the location of the plant), the resulting capital costs may be very different. Comparing the capital costs of different technologies has to be done with the utmost care, if possible identifying the specific technical, operating and financial characteristics of the plants that are being compared.

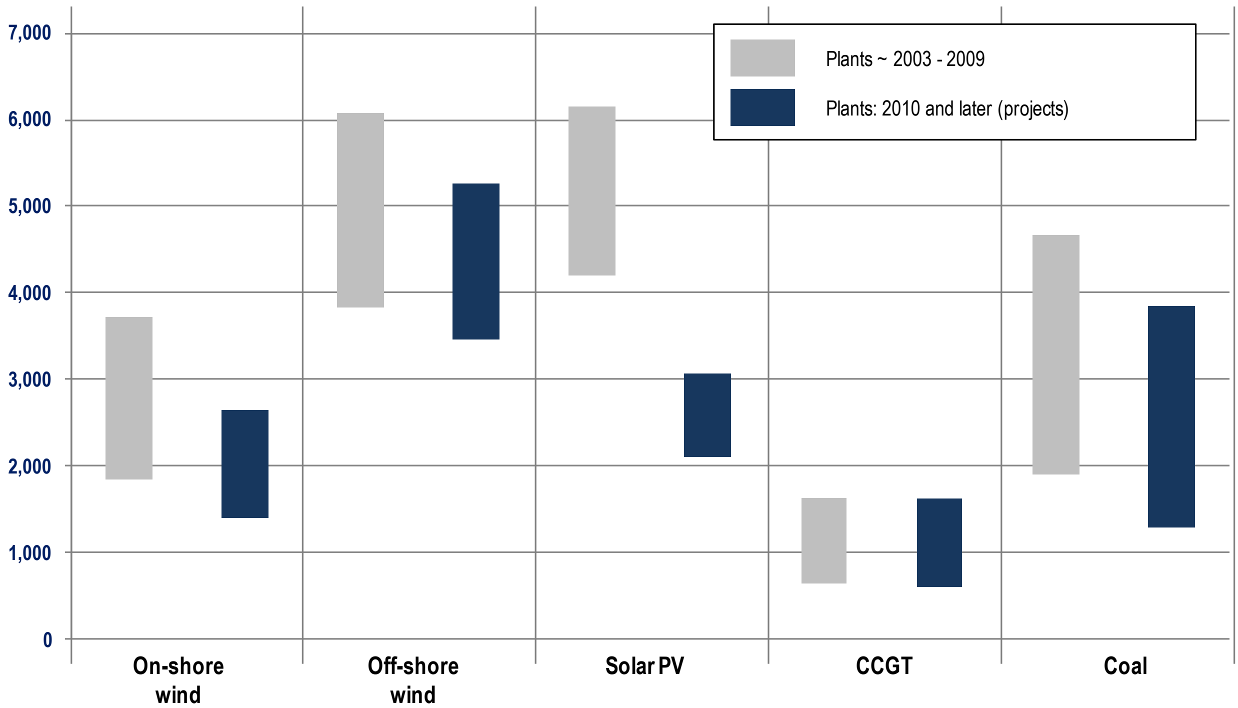

Figure 48. Evolution of capital costs – New plants and projects vs. older plants (US$/kW)[81]

[81] Ranges exclude Japan to eliminate the impact of specific cost factors that do not affect other regions.

- The unit capital costs (US$/KW) of newer RET plants (**wind and large solar PV**) appear to be lower than the capital costs of older RET plants operating in similar circumstances[82]. The main factor behind this trend is technology improvements.
- The capital costs of **gas-fired plants** have not changed as much as those of other technologies.
- The capital costs of best in class **coal-fired plants** appear to be decreasing. The main driver behind this trend would be scale. However, there is significant variation in the capital costs from one plant to another. Some new coal-fired plants may have higher capital costs than older plants of similar size, operating in similar conditions.

LCOE of generation: But capital costs are only a part of the picture. To fully gauge the behavior of different generation technologies, it is necessary to also consider other factors, for example, other costs (operating and end of life costs); operating conditions (quality of input factors, plant location); the market situation (affecting the capacity factor of each plant); and applicable support policies and incentives. Figure 49 displays the results of simulations that use the RE-COST database, and compares them with ranges of generation costs of older plants found in a number of publicly available reports and publications. Noticeable differences have been found between both.

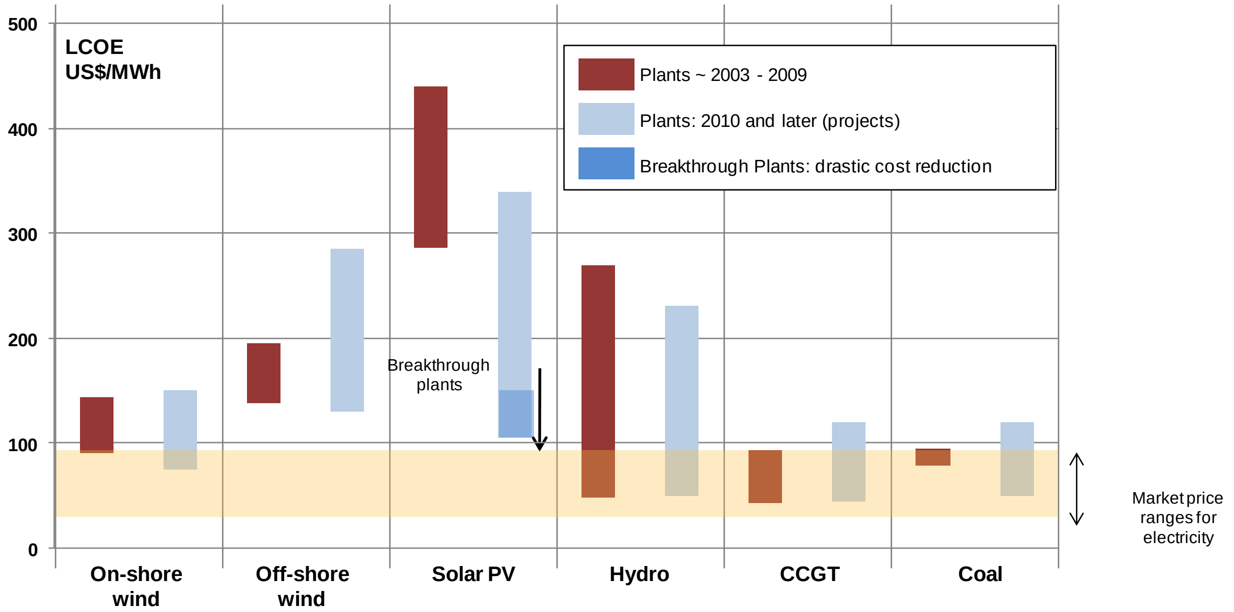

Figure 49. Evolution of generation costs – New plants and projects vs. older plants[83]

On-shore wind. (LCOE = 75-150 US$/MWh). Plants that benefit from favorable technical and operational factors – that is, large plants with scale economies, operating at high capacity factors, and financed with low to medium rates of interest – may start displaying cost ranges that approach the costs of generation of traditional technologies such as gas, coal and hydro. Different factors contribute to this outcome:

- **Reduction of turbine prices** in the last two years, driven by the emergence of suppliers in developing countries, and by price wars between turbine manufacturers.
- **Additional reductions in O&M costs**, driven by increased operational efficiencies, and by the use of lower cost suppliers.

[82] Results obtained from simulations with the RE-COST model.

[83] Ranges exclude Japan to eliminate the impact of specific cost factors that do not affect other regions.

- The on-shore wind sector is **becoming mature**. For the last 10-20 years, actors in the sector have leveraged learning and experience to reduce costs. Further cost reductions may be perfectly possible, but they may not be as significant as those seen in the last years. The learning curve is flattening.
- **Optimal locations are becoming more difficult to find**. This contributes to increasing the LCOE of new on-shore wind plants in some countries such as France and Germany[84].

The average **costs of on-shore wind generation are still higher than the market prices of electricity** in the countries and regions in the scope of this study. However, the costs of some plants that benefit from technical and operating conditions which position them in the low ranges of generation costs (low capital costs, high capacity factors, and low discount rates) may be approaching market prices in some regions. In the short term, some on-shore wind plants could attain positive business cases without needing incentives[85].

- On-shore wind could be competitive in the short or medium term in thermal countries/regions (Ontario, France, Germany, and Japan), where prices are defined by coal, CCGT, and nuclear generation.
- On-shore wind is likely to find it difficult to compete without incentives in regions with very low gas prices, such as Alberta, where electricity prices are defined by low costs of gas; or in regions such as Quebec, Norway, and Sweden, where large proportion of low cost hydro generation contribute to reduce the market prices of electricity[86].

Off-shore wind (LCOE = 130-285 US$/MWh). The unit costs of off-shore wind generation are higher than those of on-shore wind due to an array of technical and financial factors. Issues associated to new developments; the challenges of operating off-shore; and uncertainty about the future behavior and operating conditions of off-shore projects contribute to increase the costs of this technology.

In other publications, the ranges of generation costs of new off-shore wind plants appear to be smaller than those obtained by the RE-COST study. This would be consistent with reports from actors in the electricity sector that claim to be attaining significant cost reductions from technical improvements, as well as from increased experience with this technology. Still, the large cost ranges obtained in this study reflect high levels of uncertainty about final project costs. More data from operating plants are necessary to calculate the costs of off-shore generation with the same level of accuracy that has been reached in the analyses of other, older technologies[87].

At the present, the costs associated to this technology are still much higher than the reference prices of electricity in the countries in the scope of this study. Off-shore wind plants are viable only when specific incentives for this technology exist.

Large Solar PV (ground-mounted) (LCOE = 165–400 US$/MWh). The results obtained from the analyses of new solar PV plants and projects are consistent with some aspects of the traditional view of the technology. The costs of solar PV generation are still higher than the costs of other generation technologies in the scope of this study. Also, even when operating in very good conditions, most of the plants in the database display costs much higher than the reference prices of generation in all the regions evaluated.

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[84] This statement is not valid if plants in attractive locations are repowered. But the analysis of repowering has been determined as outside of the scope of this report: Repowered plants have not been included in the RE-COST database.

[85] An example is the A-5 2012 auction celebrated in Brazil in December 2012, which set up a price of 112 reals/MWh (42 US$/MWh), although with some special conditions.

[86] Strictly speaking the prices of electricity in Norway and Sweden are determined by the high proportion of low cost hydro in the Nordic market (see section 6.7).

[87] With the available data it is not possible to assert that the costs of off-shore wind generation are decreasing over time. The database of plants does not have enough granularity to allow time analysis, because the number of projects in the countries in the scope is still relatively small.

However, the costs of the newest plants included in the database are significantly lower than the costs of older plants also included in the database. Technical advances and increased experience with the technology contribute to this trend. Some of the companies interviewed claim to be able to attain much lower costs of generation than those of the average solar PV plant (10-20 MW, 15-20% capacity factor and 8-12% discount rate), and to be ready to reach grid parity in the near future (LCOE = 130-240 US$/MWh)[88]. These plants with much lower costs, which are denominated throughout the study as "breakthrough plants", to recognize their position at the cutting edge of the technology today, may become commonplace in the next 2-4 years.

For the time being, solar PV plants still need policy support to operate profitably, but the breakthrough plants may be able to operate with very small or nil revenue incentives in the near future.

CCGT (LCOE = 45-120 US$/MWh). The costs of generation of new gas-fired plants appear to be slightly higher than those of old plants. This appears to be due to two factors:

- New gas plants in many regions in the scope of the study are operating at very low capacity factors (average ~20-40 %). This further increases their costs of generation. The exception is plants operating in regions with low cost of fuel, such as Alberta[89].
- New plants have slightly higher capital costs than older plants. This would be consistent with industry analyses. Experts assert that capital costs are likely to drop in the near future due to actions conductive to eliminate the inefficiencies that caused the increase[90].

Coal (LCOE = 50-120 US$/MWh). As it is the case with gas generation, the costs of new coal plants appear to be slightly higher than those of older plants.

- New coal plants in many regions in the scope of the study operate at relatively low capacity factor (average 30-50 %). This further increases the costs of generation.
- The capital costs of new coal plants in the RE-COST database appear to be slightly higher than those of comparable older plants[91].

Additional considerations: Changes in some key cost factors may significantly affect the costs of generation of any technology:

- The most important is the **rate of interest** used to finance the plants. Everything being equal, different rates of interest may significantly affect the final costs of generation.
- Other factors, such as **insurance, emission costs, decommissioning costs,** etc. have lower importance in the business case of most plants. But they also add to the final cost tally of the project. In plants with thin business cases, these costs may represent the deciding factor between going ahead, or abandoning a project.
- Additional costs drivers, such as **integration with the network** may significantly influence the business case of some projects (off-shore wind, for instance[92]). The main issue is not only how much cost will be allocated to a

[88] The sample of data for these breakthrough solar PV plants is very small. However, the implications of these much lower costs levels could be very significant for the future of this technology.

[89] Source: IEA – World Energy Outlook (WEO) 2012. Ministry of Energy (Alberta)

[90] Source: Future fossil fuel electricity generation in Europe: Options and consequences – JRC Reference Reports, 2009; UK electricity generation costs update (June 2010), Mott MacDonald, Investment and operation costs figure – Generation portfolio, VGB Survey 2011. Coal fired power plant construction costs, Synapse (2008)

[91] Ibid. For coal-fired generation this result has to be put in context. The number of new plants included in the analysis is relatively reduced, and data from older plants are scarce and not very detailed. The capital costs for supercritical pulverized coal plants obtained in the scope of this study may not fully represent consolidated trends of this technology.

[92] Source: Projected costs of generating electricity (2010) – IEA, NEA

given plant, but whether the plant may be connected or not to the grid, and when. The uncertainty generated by this situation may reduce the appetite of investors to commit to a given project.

- **Taxes** take away a significant portion of the income generated by each plant. Adding corporate, regional, local taxes, plus generation specific taxes may result in a plant that provides positive income to investors, but that does not supply the desired return levels.
- **Exchange rates** may influence the outcome and the success of some investments that include expenditures and revenues in different currencies.

Cost of generation vs. prices of electricity. The main consequence of these trends is that, in some countries, the costs of on-shore wind are approaching the market prices of electricity. Some of the best-in-class plants[93] analyzed appear to display costs that are in the higher ranges of the reference prices of electricity of some of the regions considered. It might be expected that in the short term, some on-shore wind plants might display positive business cases without the need of incentives in regions where the prevalent prices for electricity generation are high enough.

The costs of other new RET, such as solar PV and off-shore wind, are higher than the reference prices of electricity in the practical totality of the regions in the scope of the study. They require incentives to compete against other forms of generation. However, the trends identified by this study and by other publications suggest that, at some point in the future, these two technologies could be at parity with the prevalent prices of electricity generation in these regions[94].

The relative competitiveness of new RET, and the likelihood that wind and solar PV plants can forego incentives in the future is very dependent on the prevalent prices of electricity. Prices that in turn depend on the supply mix of each of the regions/countries analyzed by RE-COST.

- New RET could be competitive in the short-medium term in thermal countries (France, Germany, Sweden, Spain), where prices are defined by coal, CCGT, nuclear generation.
- However in the short term new RET will still find it difficult competing in regions with very low gas prices, such as Alberta, where electricity prices are defined by low costs of gas.
- New RET plants – even the best-in-class on-shore wind farms – are likely to be uncompetitive in hydro regions/countries such as Norway, Sweden and Quebec in the long term. Approaching the very low prices of generation associated with large proportions of hydro generation is going to require significant cost reductions, not likely in the very short term (2-3 years).

In addition, one key factor to determine whether new RET plants may be able to operate without incentives in the future will be the extent of support and incentives that other forms of generation are awarded. As discussed in Section 3.10, non-RET plants may also receive incentives that affect their generation costs. Reducing and ultimately discontinuing incentives to RET generation should be done only in a framework in which the incentives to all types of generation are considered, both RET and non-RET.

[93] Depending on the country/region: onshore wind farms with 30-35% capacity factor, size 50-100 MW and discount rate 5-8%

[94] Database includes data with very low capital cost – breakthrough plants

3.2 Canada – Alberta

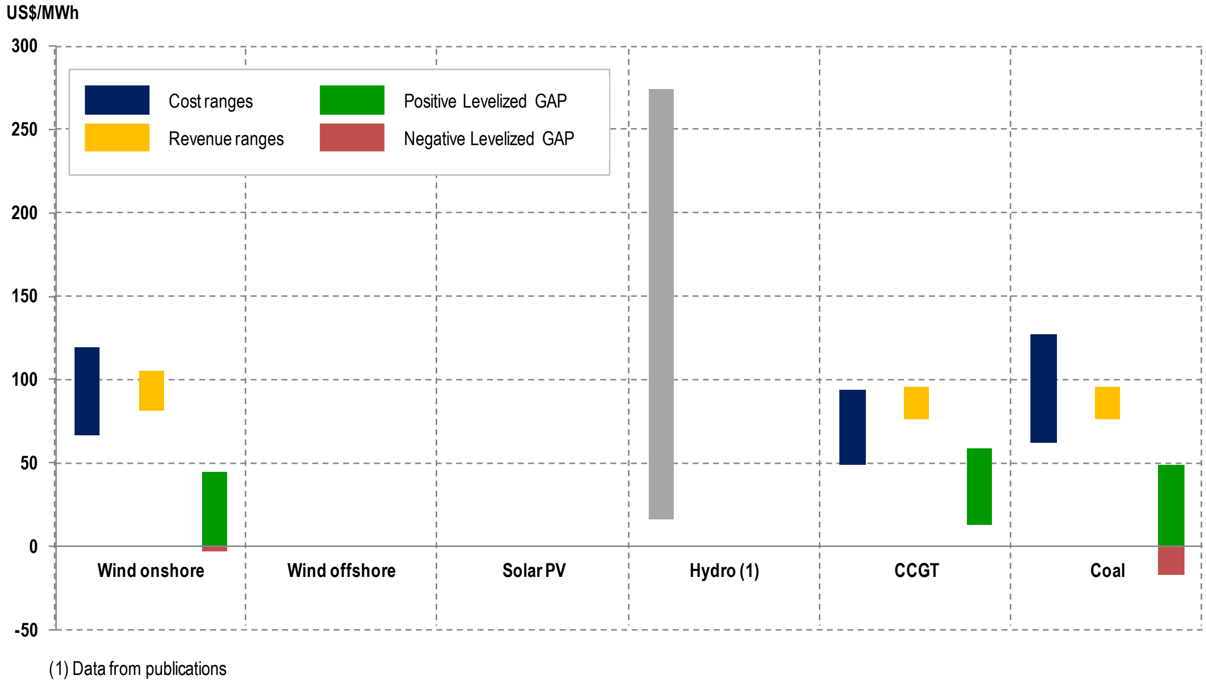

Figure 50. Alberta – Ranges of unit costs and revenues (US$/MWh)[95]

Alberta / On-shore wind: Simulations of Alberta's plants result in average on-shore wind costs higher than the average cost of gas-fired plants in the region, and roughly at the same or at lower levels than those of coal-fired plants.

Best-in-class on-shore wind plants (Size 75-100 MW, capacity factor 30-35% and discount rate 5-8%), which benefit from low interest rates, advantageous turbine prices, and high capacity factors, may reach costs of generation lower than the costs of some thermal plants (coal ~ 70 US$/MWh). However, these plants are not representative of all the on-shore wind plants in Alberta, as average plants (Size 20-50 MW, capacity factor 25-30% and discount rate 6-10%) still display higher costs than those of thermal plants. These average plants still need policy support to operate profitably.

It may be advisable to frequently evaluate the evolution of on-shore wind costs in order to identify how the cost gap between on-shore wind and other generation technologies evolves in the future in the province.

Alberta / CCGT: The business case of new CCGT is very positive in the province. New gas-fired plants appear to have slightly higher capital costs than older plants, but this is amply compensated by the very low costs of gas in Alberta.

Alberta / Coal: New coal-fired plants present advantageous business cases to investors if they can operate consistently at high capacity factors (45-60%). Plants with capacity factors lower than 45% may find it difficult to result in profitable operations, unless they secure higher prices than the market average (though balancing revenues, OTC contracts, or other).

[95] Result of 15-20 simulations by country-technology pair using RE-COST model (based on the data obtained in the interviews). Incentives are included.

CANADA-ALBERTA	On-shore Wind	Off-shore Wind	Solar PV	Hydro	CCGT	Coal
# Plants in the database	5	NO	NO	Approx	2*	3*
Size ranges (MW)[96]	50-80				200-800	250-600
Business case	✓				✓	✓

*Note: Includes data from publications. See Figure 180

✓ Profitable ! Profitability issues ✗ Not profitable ↔ Uncertain → Impact of policy changes

Region/Technology pairs (scope of analysis) Does not exist or irrelevant Not included in the study

Figure 51. Alberta – Business cases (BC) summary of results

3.3 Canada – Ontario

Given the average costs of generation of new RET (wind, large solar PV) in the, it would be difficult for investors to define attractive business cases at the current market prices of electricity in Ontario, Therefore, new RET – including new hydro – are supported with incentives that enable developers and investors to cover costs and to reap a measure of profitability. The incentive scheme in Ontario appears to be adjusted to benefit best in class plants. Simulations show that investors in solar PV, on-shore wind and new hydro should be able to define attractive business cases in Ontario, if they significantly adjust their costs.

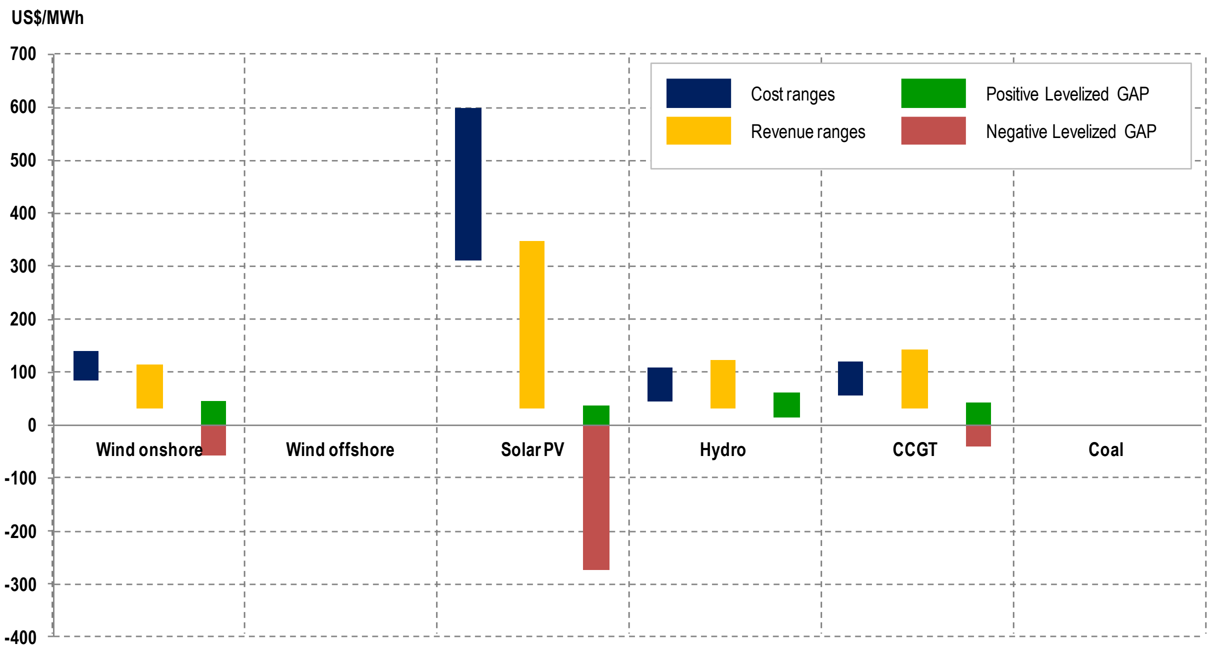

Figure 52. Ontario – Ranges of unit costs and revenues (US$/MWh) [97]

[96] Represent size ranges that can be used in the simulation model, not the sizes of the plants in the database

[97] Result of 15-20 simulations by country-technology pair using RE-COST model (based on the data obtained in the interviews). Incentives are included.

Ontario / On-shore wind: Best-in-class on-shore wind plants benefiting from low interest rates (3-7%), advantageous turbine prices, and high capacity factors (30-35%) would generate enough profitability to interest investors, even with the recent reductions in the level of incentives in this province[98].

Ontario / Large solar PV: The policy changes introduced by the government of Ontario in 2012 appear to be putting significant pressure on investors in solar PV. At the current compensation levels for solar PV electricity, only plants with LCOE at 300-350 US$/MWh may define profitable business cases in Ontario.

Ontario / Hydro: The current incentives for hydro generation are sufficient to generate positive business cases for new small- and medium-scale hydro plants. But the profitability of new hydro projects is by no means ensured. Investors must conduct careful assessments before committing to a given project.

Ontario / CCGT: New gas-fired plants with contracts with the Ontario Power Authority (OPA) of about 82-142 US$/MWh[99] would be profitable. But a gas-fired plant operating without an OPA contract (at market prices), would find it difficult to obtain positive business cases.

CANADA-ONTARIO	On-shore Wind	Off-shore Wind	Solar PV	Hydro	CCGT	Coal
# Plants in the database	>10	NO	1*	2*	2*	NO
Size ranges (MW)[100]	5-200		1-80	10-100	200-800	
Business case	✓ ↔ !		✓ ↔ !	✓	✓	

*Note: Includes data from publications. See Figure 180

✓ Profitable ! Profitability issues ✗ Not profitable ↔ Uncertain → Impact of policy changes

Region/Technology pairs (scope of analysis) Does not exist or irrelevant Not included in the study

Figure 53. Ontario – Business cases (BC) summary of results

3.4 Canada – Quebec

Quebec is one of the regions with the highest proportion of hydro generation in the world. Legacy hydro generation is the main factor behind the very low prices of electricity in the province. The reference prices of electricity used in the simulations were 27.9 US$/MWh, corresponding to the prices paid by Hydro-Quebec Distribution to Hydro-Quebec Production[101]. As a consequence, new RET need policy support. Quebec supports new generation technologies through RFPs (requests for proposal) that enable suppliers to attain higher generation prices than it would be possible if they were selling the electricity produced at "market prices" (See Section 6.4).

[98] Source: Ontario´s Feed-in Tariff Program – Ontario Power Authority. Original FIT on-shore wind Price 13.5 (CA$ c/kWH), New FIT Price 11.5 (CA$ c/kWH)

[99] Source: Ontario Power Authority. Cost Disclosure – Generation Supply

[100] Represent size ranges that can be used in the simulation model, not the sizes of the plants in the database

[101] Electricity prices are defined by An Act of the Régie de l'Énergie.

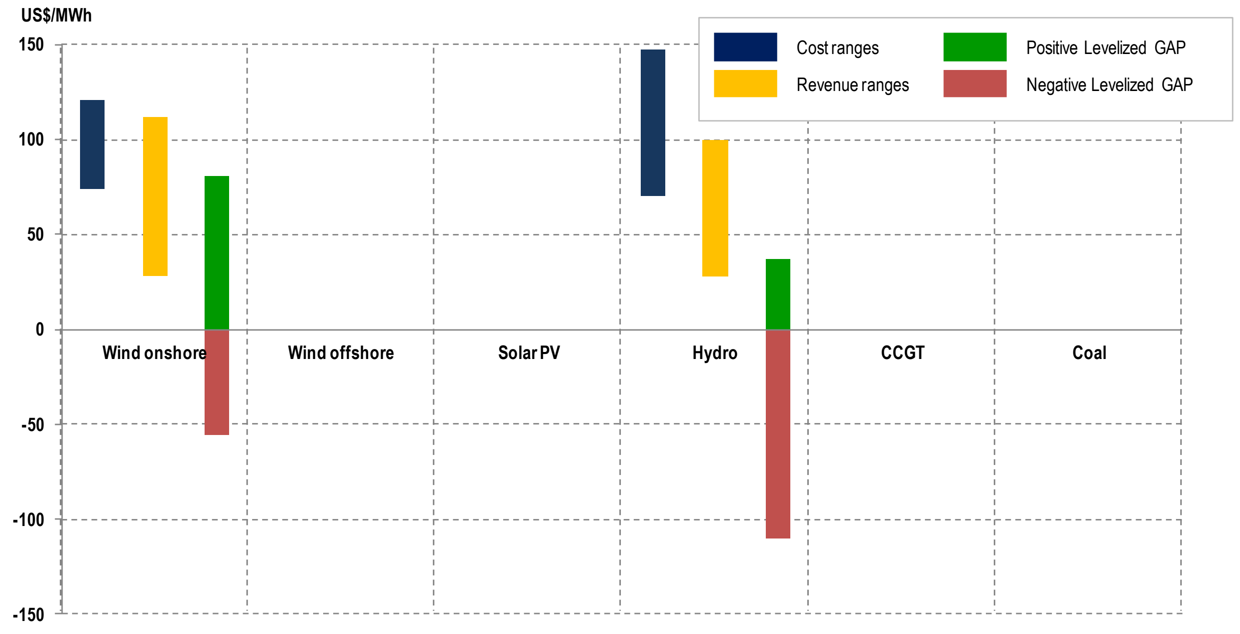

Figure 54. Quebec – Ranges of unit costs and revenues (US$/MWh) [102]

Quebec / On-shore wind. The business case of each plant will depend on the specific agreement established by the producer with Hydro Quebec, agreement that is not public. However, with the data existing in the public realm, it is possible to assert that the current incentive[103] system in Quebec appears to provide reasonable rates of returns to investors in on-shore wind. Section 6.4 discusses in more detail the simulations that have been conducted to gauge the results of the business cases for the RFPs that have been called by Hydro-Quebec in the last years.

Quebec / Hydro: Investors in small hydro need to receive policy support to operate profitably. Simulations show that investors require at least 70-80 US$/MWh to turn a profit. These compensation levels appear to be in the vicinity of the prices paid by Hydro Quebec to small hydro suppliers[104].

CANADA-QUEBEC	On-shore Wind	Off-shore Wind	Solar PV	Hydro	CCGT	Coal
# Plants in the database	5	NO	NO	1*	NO	NO
Size ranges (MW) [105]	100-140			10-100		
Business case	✓			✓		

*Note: Includes data from publications. See Figure 180

✓ Profitable ! Profitability issues ✗ Not profitable ↔ Uncertain → Impact of policy changes

Region/Technology pairs (scope of analysis) Does not exist or irrelevant Not included in the study

Figure 55. Quebec – Business cases (BC) summary of results

[102] Result of 15-20 simulations by country-technology pair using RE-COST model (based on the data obtained in the interviews). Incentives are included.

[103] Prices paid by Hydro Quebec in the RFPs for on-shore wind generation carried out by the utility are approximate

[104] Prices paid in the RFP for small hydro are not available. Data from interviews.

[105] Represent size ranges that can be used in the simulation model, not the sizes of the plants in the database

3.5 France

Traditionally, the power generation mix in France has been based on a combination of thermal, hydro, and nuclear plants. This has resulted in relatively low electricity prices. At the prevailing market compensation levels, new RET (on-shore and off-shore wind, and solar PV) require policy based incentives to define positive business cases. The incentives defined by French policy makers to support the renewable technologies in the scope of this study appear to provide reasonable rates of return to plants in the medium-low ranges of generation costs.

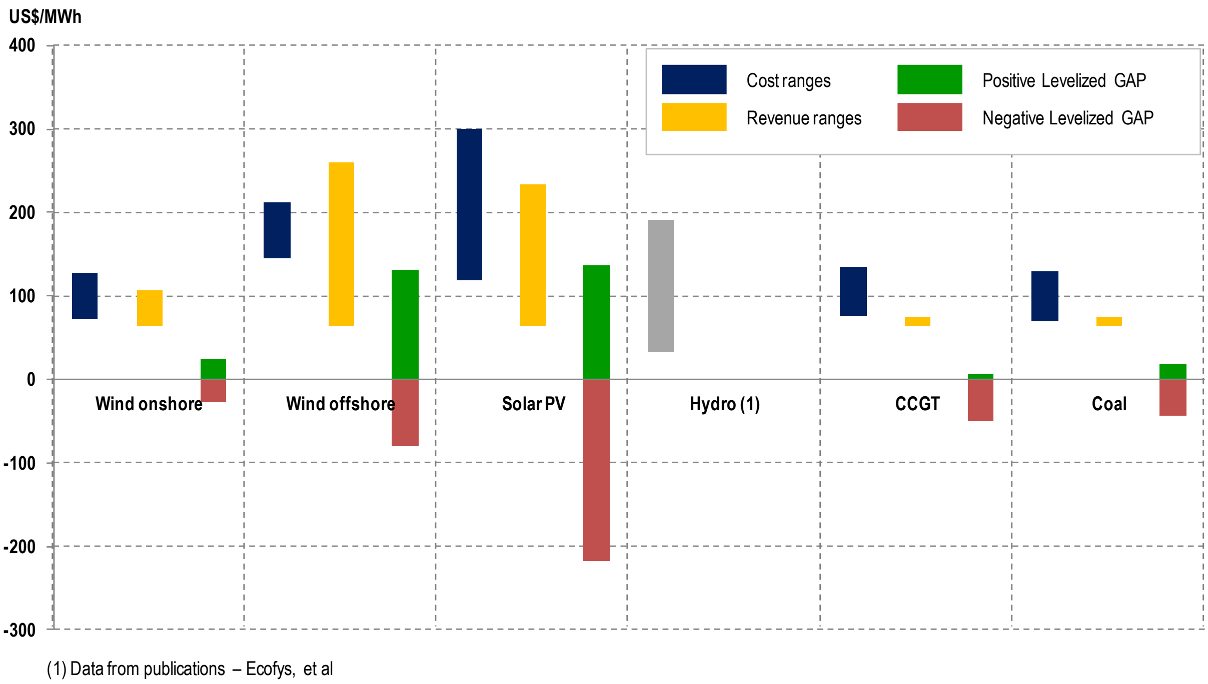

Figure 56. France – Ranges of unit costs and revenues (US$/MWh) [106]

France / On-shore wind: The current FIT for on-shore wind in France appears to provide enough margins only to plants in a range of technical and operating conditions which position them in the low ranges of generation cost, (50-100 MW, 30-35% capacity factor and 5-8% discount rate).

France / Off-shore wind: There is significant uncertainty about the levels of costs that off-shore wind generation will attain in France once the plants are in operation. However, the simulations conducted using the RE-COST database and publicly available data show that the current incentive system would be adequate to develop off-shore wind. The RFPs recently launched appear to provide participants with enough profitability to invest in off-shore wind; but the compensation levels established would not result in windfall profits. (Ranges of prices to producers have been assumed to be in the range of 200-260 US$/MWh[107]).

France / Large solar PV: Likewise, the recent RFPs for solar PV in France appear to have been adjusted to provide enough margins to investors to ensure their participation in the scheme, while simultaneously avoiding windfall profits (117-240 US$/MWh[108]). The scheme, as it is defined at the present, should enable the addition of solar PV

[106] Result of 15-20 simulations by country-technology pair using RE-COST model (based on the data obtained in the interviews). Incentives are included.

[107] There is no official information about the compensations that will be paid to winners of the recent off-shore wind RPFs in France. The prices used by RE-COST, have been obtained from expert interviews, and industry publications

[108] Source: Interviews and Prysma analysis

plants with good levels of generation costs (119-232 US$/MWh). This would favor the introduction of breakthrough technologies in solar PV generation.

France / CCGT and Coal: New non-RET plants (gas and coal-fired) face a challenging situation. These plants need to reach relatively high capacity factors (above 60% for coal plants, and 75% for CCGT) to attain positive business cases. Reaching these utilization levels is not straightforward in the market and policy conditions prevailing in the power sector in France today. As a consequence, most investments in new gas and coal-fired plants in France are likely to face profitability issues.

FRANCE	On-shore Wind	Off-shore Wind	Solar PV	Hydro	CCGT	Coal
# Plants in the database	3	1*	3	Approx	2	3
Size ranges (MW)	10-100	100-600	1-50		200-600	250-600
Business case	!	✓	✓		!	!

*Note: Includes data from publications. See Figure 180

✓ Profitable ! Profitability issues ✗ Not profitable ↔ Uncertain → Impact of policy changes

Region/Technology pairs (scope of analysis) Does not exist or irrelevant Not included in the study

Figure 57. France – Business cases (BC) summary of results[109]

3.6 Germany

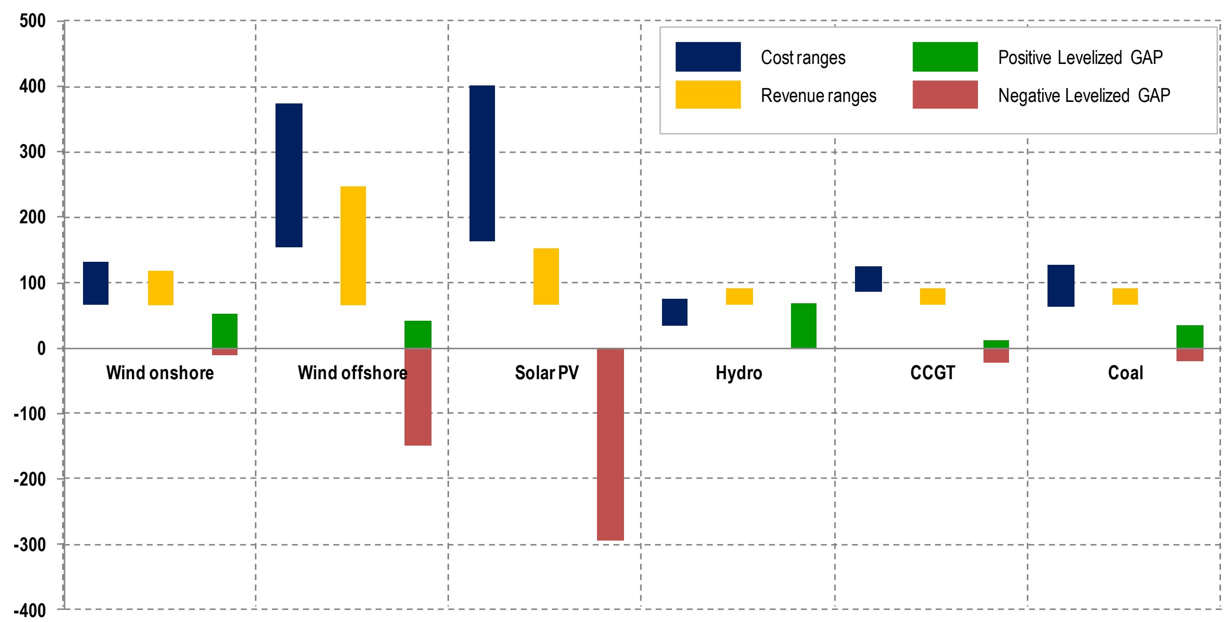

Figure 58. Germany – Ranges of unit costs and revenues (US$/MWh)[110 111]

[109] Represent size ranges that can be used in the simulation model, not the sizes of the plants in the database

[110] This is an example with data considered for 2012. Any applicable degressions for FIT (incentives) have been calculated in the RE-COST model.

Traditionally Germany has shown strong support to RET. This has enabled significant development of wind and solar PV generation[112] in this country. Recently, the German administration has updated the schemes and levels of support to RET in order to better adapt the incentives provided to the evolving cases of generation for each technology. As discussed in Section 6.6, the compensation levels that RET plants may attain depend on a number of factors such as technology, plant location, date of commissioning, time in operation, type of scheme used (FIT or market premium, etc.). The actual business case of a new plant is going to depend not only on its technical and operating characteristics, but also on the actions of the plant managers, and in their ability to proactively manage the stream of revenues during the lifetime of the plant. This results in a wide range of potential business cases for similar plants.

Germany / on-shore wind, large solar PV: During 2011 and the first 9 months of 2012, the FIT levels awarded to on-shore wind and large solar PV were sufficient to ensure enough levels of profitability to investors in these technologies. 50-100 MW on-shore wind plants, with average capacity factor 30-40%, and 5-10% discount rate; and 10-50 MW solar PV plants, with capacity factor 20-30%, and discount rate 4-10% appeared to receive enough compensation with the FIT scheme.

The EEG revision in 2012[113] resulted in changes of the FIT levels payable to new generation plants. Simulations show that the new FIT reduces the profitability of new on-shore wind plants, but still provides enough margins to generate interest in this technology. However, the newly established FIT for large solar PV makes it difficult for investors to define advantageous business cases. If managers opt for FIT payments[114], only new best-in-class plants with low capital costs, high capacity factors, and able to gradually reduce O&M costs over the life of the plant, may be able to generate sufficient profits.

However, managers may also opt for the marketing premium scheme. Simulations show that investors in on-shore wind and solar PV may define relatively advantageous business cases for new plants, if they devote the time and effort necessary to optimize the returns of their projects. Section 6.6 discusses the potential implications of using the FIT, or the market premium scheme.

Germany / off-shore wind: Off-shore wind farms, which operate at high utilization levels and which benefit from accelerated learning and technical improvements resulting in low capital costs, should be able to present positive business cases to investors in. However, uncertainty about costs and timing of connection appear to be damaging the business cases of some existing plants.

Germany / hydro: Costs of large hydro plants in Germany are in-line with the market prices of electricity in this country. Large hydro plants (>30 MW), with capacity factors equal or larger than 40%, would provide reasonable returns at spot and wholesale market prices. For small hydro plants, the business case is positive, but very sensitive to the size and capacity factor of the plant.

Germany / gas and coal: The picture for investors in these plants is mixed. Low capacity factors damage the business cases of gas and coal generation. But simulations show that some best in class gas plants (>400MW, capacity factor >75%, and financing rates <9%); and some coal plants (>1000MW, capacity factor >60%, and financing rates <8%) which receive revenues slightly above the current spot price of electricity, may yield sufficient profitability to interest investors in these technologies. In particular, coal plants may have a window of opportunity at the present triggered by relatively low prices of coal in Germany, and by the very low prevailing prices that emissions have reached (3 US\$/tCO_2 today versus 10-12 US\$/tCO_2 of 3 years ago). The main issue is whether these

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[111] Result of 15-20 simulations by country-technology pair using RE-COST model (based on the data obtained in the interviews). Incentives are included.

[112] Also biomass had a significant development, but is out of the scope of this study

[113] Revenues: renewable FIT as of 2012 including natural degression; non-RET electricity market prices.

[114] This may be a transitory situation, because previous rates provided enough revenues for the development of solar PV and in the future, current rates may be enough if the cost trends continue as expected.

current advantageous conditions will continue during the average lifetime of a coal-fired plant (40 years). Investors appear to be interested in the potential profitability of coal in Germany, but may hesitate to commit large amounts of capital in the development of additional installed coal capacity, in light of the uncertainty associated to key factors of coal generation costs.

The outlook of generation in Germany may significantly change if prices of electricity increase in the future. For example, 20% increase in average prices of generation would put average plants of any technology in the black (see Section 6.6).

GERMANY	On-shore Wind	Off-shore Wind	Solar PV	Hydro	CCGT	Coal
# Plants in the database	3	1*	3	(pub)	3	>10
Size ranges (MW) [115]	10-100	100-600	2-50	10-100	200-1,000	450-2,500
Business case	✓ ↔ !	!	✓ → ✗	✓	!	✓

*Note: Includes data from publications. See Figure 180

✓ Profitable ! Profitability issues ✗ Not profitable ↔ Uncertain → Impact of policy changes

Region/Technology pairs (scope of analysis) Does not exist or irrelevant Not included in the study

Figure 59. Germany – Business cases (BC) summary of results

3.7 Norway – Sweden

The joint support scheme in Norway and Sweden consists of green certificates that provide additional revenues to eligible RET plants. Some aspects of the scheme are still being evaluated and discussed, especially in Norway which did not introduce green certificates until 2012:

- It is **not clear yet whether using market prices of attributes is enough to incentivize** the development of new wind plants, given the low prices that alternative sources of renewable energy have in Norway and Sweden (hydro or biomass). However, it may be contended that if the scheme is well defined, increasing demand of certificates will increase their prices to high enough levels to cover the cost of new developments.
- Some Norwegian sources claim that the **scheme may be more advantageous initially for Sweden** because it has been using it longer, while Norwegian producers have to catch up.
- **Differential characteristics** in the markets and the environments of both countries may benefit one or the other. For instance, it has been claimed that higher taxes in Norway than in Sweden (for example, property taxes) may favor the installation of plants in Sweden. But it could also be argued that better quality of wind resources in some regions in Norway could provide an advantage to wind farms in this country because they would operate at higher capacity factors. Comparative analyses of the Norwegian and Swedish wind plants included in this study do not appear to show statistically significant differences in costs of generation, and resulting business cases, (see Figure 149 in Section 6.7).

Norway and Sweden / On-shore wind: The simulations conducted in the scope of RE-COST show that new on-shore wind may present attractive business cases to investors in both countries[116], provided they deploy plants

[115] Represent size ranges that can be used in the simulation model, not the sizes of the plants in the database

[116] The price of certificates is set up by the market and should be the same for both countries. Official sources display values slightly different: 21-28 US$/MWh (120.1-160.2 NOK/MWh) in Norway and 24-30 US$/MWh (158.6-198.3 SEK/MWh) in

that operate in average to best in class costs levels (50-100 MW, 30-40% capacity factor and 5-8% discount rate). Green certificates, at the price levels they have reached in the last months of 2012, are able to bridge the gap between the costs of generation of new on-shore wind plants, and the average compensation of electricity in Norway and in Sweden.

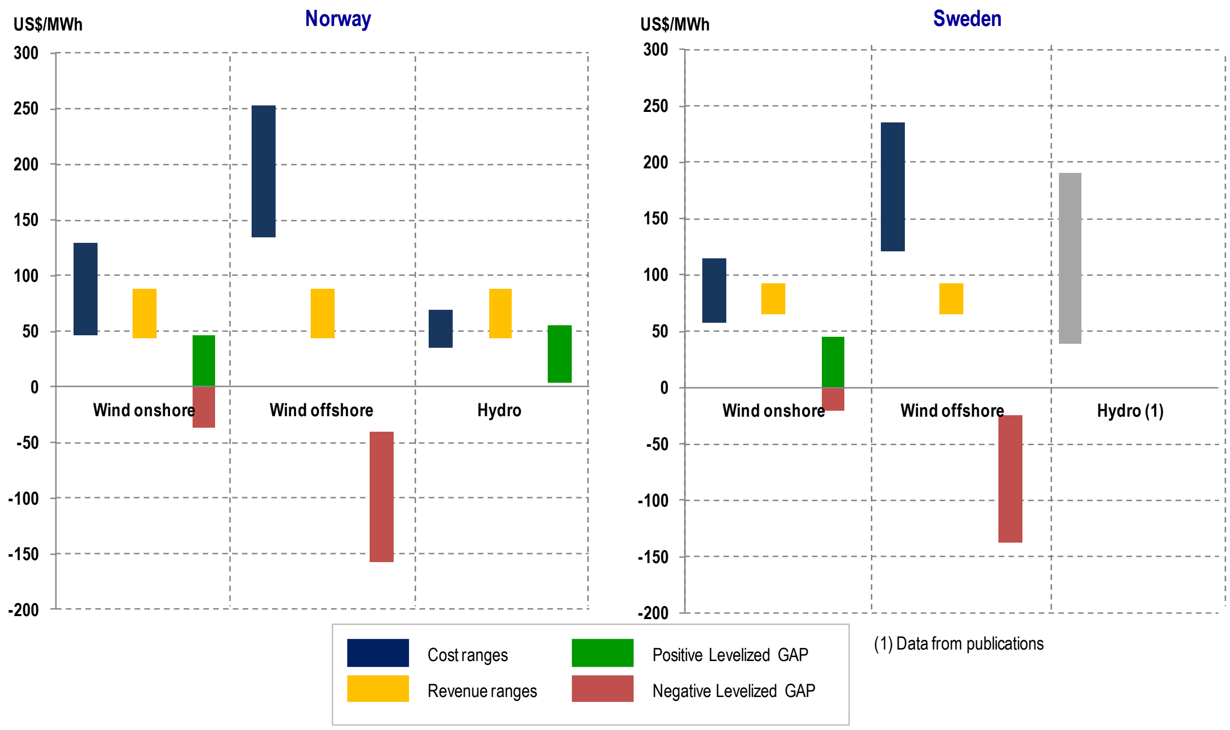

Figure 60. Norway and Sweden – Ranges of unit costs and revenues (US$/MWh) [117]

Norway and Sweden / Off-shore wind: Green certificates, at the average price levels reached in 2012, are not enough to compensate investors in off-shore wind projects in Norway or Sweden. Unless additional policy support is forthcoming, or unless the price of certificates significantly increases[118], it is unlikely that investors will be interested in this technology in the short and medium terms (up to 5 years from today).

Norway / Small hydro: Simulations show that investors could obtain profitable business cases from average small hydro in Norway (5-10MW, 25-50% capacity factor, and 5-10% discount rate). However, each hydro project is different. Plants with high capital costs or poor operational characteristics are unlikely to be profitable. To ensure adequate levels of profitability, investors must carefully assess the specific characteristics of each potential project, and must ensure that the plants are financially optimized during their lifetimes.

Sweden in 2012. The simulations shown in this section use the same reference price for certificates for consistency (24 US$/MWh). This price can be modified in the model.

[117] Result of 15-20 simulations by country-technology pair using RE-COST model (based on the data obtained in the interviews). Incentives are included.

[118] Simulations show that to bridge the gap between the costs of off-shore wind generation, and the average compensation levels for electricity in Norway and Sweden, the price of green certificates should be approximately three times higher than today. Or conversely, it would be necessary to compensate each KWh produced by an off-shore wind plants with 3 green certificates, instead of with one.

The truth is that **there has been insufficient time as yet** to fully gauge the actual impact of the joint scheme. Most studies, carried out before it was in place, assert that it may eventually be successful[119]. But the jury is still out.

		On-shore Wind	Off-shore Wind	Solar PV	Hydro	CCGT	Coal
Norway	**Plants in the database**	5	1*	NO	2*	NO	NO
	Size ranges (MW) [120]	10-100	150-600		10-100		
	Business case	✓	✗		✓		
Sweden	**Plants in the database**	3	1*	NO	Approx	NO	NO
	Size ranges (MW) [121]	10-100	150-600				
	Business case	✓	✗				

*Note: Includes data from publications. See Figure 180

✓ **Profitable** ! **Profitability issues** ✗ **Not profitable** ↔ **Uncertain** → **Impact of policy changes**

Region/Technology pairs (scope of analysis) Does not exist or irrelevant Not included in the study

Figure 61. Norway and Sweden – Business cases (BC) summary of results

3.8 Spain

In January 2012, the Spanish government imposed a temporary suspension of additional economic support approvals for new generation capacity under the Special Regime[122]. All the plants that were commissioned before January 31st, 2012 will still receive a FIT. But under the current provisions, new projects commissioned after January 2012 will not be eligible to receive incentives. In addition, the RD 14/2010 established operating time limits for solar PV installations[123]. This means that in the future, solar PV plants benefiting from a FIT will be compensated through the FIT scheme only until the number of generation hours reaches a reference value. Once the time limit is reached, the plant will not receive the tariff, and will have to operate at the market prices of electricity.

Throughout 2012 additional provisions have been added to the incentive system for power generation in Spain. For example, the Spanish government has recently (2012) introduced a set of fiscal modifications: new income tax (7%) for all technologies operating within the energy sector; a fuel tax (*centimo verde*) for coal and gas-fired plants; an additional tax to hydropower facilities (2.2%-22%); and new taxes for the generation and storage of nuclear wastes (See Section 6.8).

As a consequence of policy changes and the current market situation, the business cases of new plants across all generation technologies appear to be rather negative. Most new RET plants do not present positive business cases because their costs are still higher than the reference prices of electricity in Spain, and they are not eligible to receive the tariff. Non-RET plants (gas- and coal-fired) are suffering from low capacity factors, which significantly damage their business cases.

[119] Source: Goldstein – A Green Certificate Market in Norway (2010).

[120] Represent size ranges that can be used in the simulation model, not the sizes of the plants in the database. Data from one plant, complemented with publications.

[121] Ibid.

[122] See definition of special and ordinary regimes in section 6.8.

[123] Depending on the climate zone and the technology.

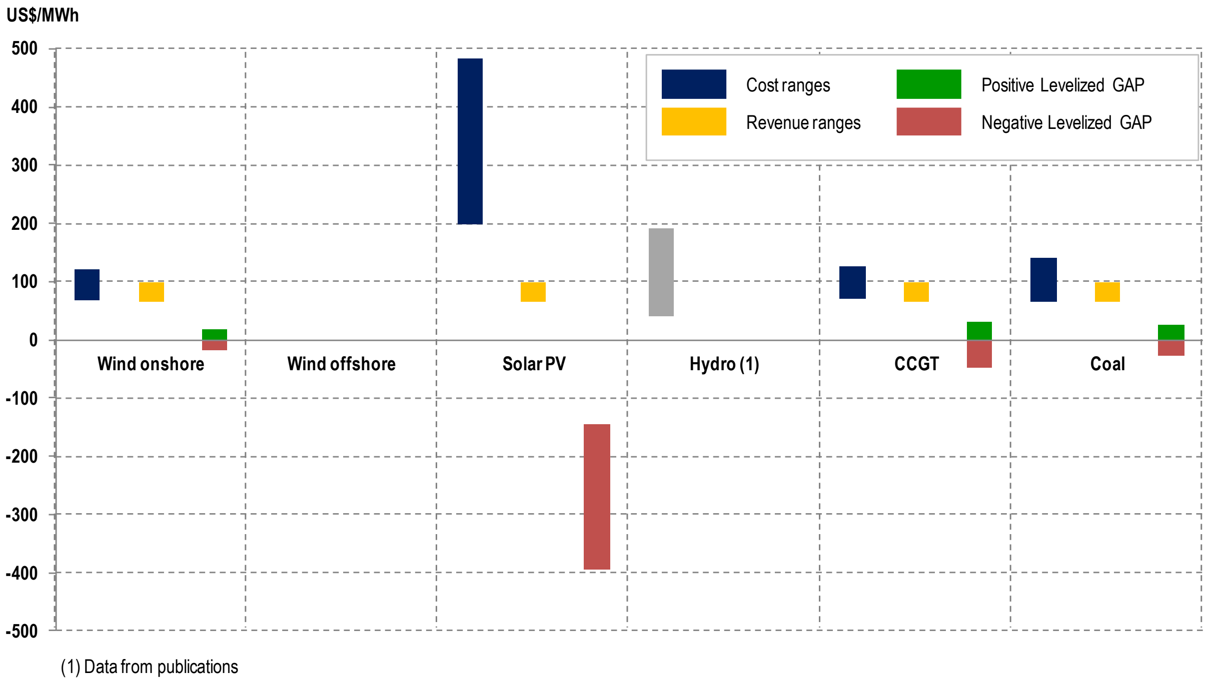

Figure 62. Spain – Ranges of unit costs and revenues (US$/MWh) [124]

Spain / On-shore wind. Average to best-in-class on-shore wind plants (25-100 MW, 25-35% capacity factor and 6-12% discount rate), which were commissioned before 2012, appear to present attractive business cases to investors in Spain. But, without an incentive scheme, the business case for on-shore wind is very thin, and only profitable for plants that consistently attain compensation levels above average spot market prices (2011). Only plants operating on islands, or in very specific locations (off the grid), may provide enough margins to investors to be considered as attractive business propositions.

Spain / Large solar PV. The situation of solar PV is similar to that of on-shore wind. Average to best in class plants (10-25 MW, 15-25% capacity factor and 6-12% discount rate), eligible to receive the prevailing FIT before 2012, appear to provide sufficient profitability to investors; even though the caps to generation times have reduced the profits margins of most operating plants. However, new solar PV plants commissioned after January 2012 are unlikely to present positive business cases. Their costs are higher than the reference prices of electricity in Spain. The business case of new solar PV plants operating in the grid would be negative.

Spain / Gas- and coal-fired: New gas- and coal-fired plants need to operate at capacity factors of at least 50% to break-even. But not many potential new plants would be able to attain these relatively high utilization levels[125]. Although there may be exceptions: plants designed to provide balancing capacity, or to fulfill specific roles in the grid may theoretically present positive business cases. But investors appear to be wary: interviews carried out in the framework of RE-COST have not identified any real case of new thermal (gas- and coal-fired) plant being developed in 2012.

In these conditions, it is unlikely that many investors will seriously commit to large additions of generation capacity in Spain in the short term.

[124] Result of 15-20 simulations by country-technology pair using RE-COST model (based on the data obtained in the interviews). Incentives are included.

[125] Average utilization of these technologies in 2011 was 22% for gas-fired plants and 43% for coal-fired plants

SPAIN	On-shore Wind	Off-shore Wind	Solar PV	Hydro	CCGT	Coal
Plants in the database	4	NO	3	Approx	3	3
Size ranges (MW) [126]	10-100		2-15		300-850	250-600
Business case	✓ → ✗		✓ → ✗		✗	!

*Note: Includes data from publications. See Figure 180

✓ Profitable ! Profitability issues ✗ Not profitable ↔ Uncertain → Impact of policy changes

Region/Technology pairs (scope of analysis) Does not exist or irrelevant Not included in the study

Figure 63. Spain – Business cases (BC) summary of results

3.9 Japan

Figure 64 displays the results of the simulations of the business cases of new generation plants and projects in Japan. The relatively high incentive levels awarded to RET reflect the strong interest of the Japanese policy makers in the development of alternative sources of generation.

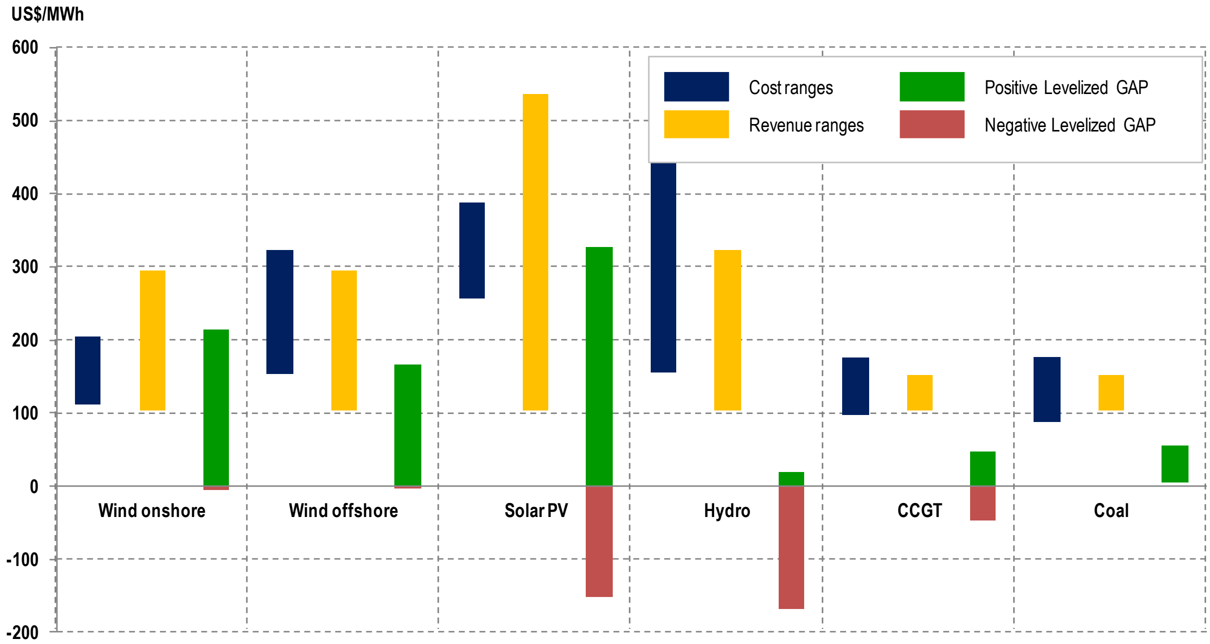

Figure 64. Japan – Ranges of unit costs and revenues (US$/MWh) [127]

Industry interviews and simulations yield higher costs of generation for all the technologies in the scope of the analysis[128]. Interviews have confirmed that the high costs observed respond to the special characteristics of the Japanese electric sector, with grid fragmentation and poor interconnections between regions, high land costs, and high construction costs due to stringent earthquake-related regulations, and to other factors. Independent

[126] Represent size ranges that can be used in the simulation model, not the sizes of the plants in the database

[127] Result of 15-20 simulations by country-technology pair using RE-COST model (based on the data obtained in the interviews). Incentives are included.

[128] The ranges of costs calculated are consistent with the ranges provided by Japanese electricity sector.

investors may have also to cope with some difficulties when attempting to connect to the networks of the EPCOs[129].

Japan / On-shore wind: With the current incentive system, even on-shore wind plants that operate in average conditions (15-30 MW, 25-30% capacity factor, and 8-12% discount rate), with higher average costs of generation than similar plants in Europe or Canada, may be able to realize attractive returns in Japan. But they need to ensure connection to the grid. This issue may limit the efficiency of the system.

Japan / Off-shore wind: Large plants (200-600 MW), with high capacity factors (35-45%), and low rates of finance (5-11%) may return reasonable profits to investors. However, since the tariff level is the same for on- and off-shore wind, it may be much more rewarding to invest in an on-shore project than in an off-shore project, as higher returns at lower costs can be expected. Ensuring connection to the grid appears to become a key factor for investors in this technology too.

Japan / Large solar PV: With the exiting tariffs, large solar PV plants can result in attractive business cases at average operating conditions (2-10 MW, 15-20% capacity factor, and 5-8% discount rate). As a consequence, even investors who do not incorporate the latest technology breakthroughs in their developments may be able to attain relatively high margins.

JAPAN	On-shore Wind	Off-shore Wind	Solar PV	Hydro	CCGT	Coal
Plants in the database	3*	1*	1*	1*	2*	3*
Size ranges (MW) [130]	10-100	100-600	1-10	10-100	300-1,500	300-1,000
Business case	✓	✓	✓	!	!	✓

*Note: Includes data from publications. See Figure 180

✓ Profitable ! Profitability issues ✗ Not profitable ↔ Uncertain → Impact of policy changes

Region/Technology pairs (scope of analysis) Does not exist or irrelevant Not included in the study

Figure 65. Japan – Business cases (BC) summary of results

Japan / Gas-fired: Simulations result in tight business cases (low levels of profitability) for new CCGT in Japan. Only plants operating at the spot market price would be profitable. But the spot market in Japan is very small, and does not provide a good price reference for the average CCGT plant. Investors may receive lower compensation levels for the electricity generated. In the short term, they will likely be cautious, and hesitate to commit to significant deployment of gas plants.

Japan / Coal-fired: The business case of coal-fired generation is positive for average plants (1,000-2,000 MW, 55-65% capacity factor, and 5-8% discount rate). However, it has to be considered that these results hinge on plants attaining relatively high capacity factors. A return to high levels of nuclear generation in Japan, that reduced the average capacity factors of coal generation, could damage the future business case of plants based on this technology.

[129] The impact of changes in exchange rate may also contribute to higher costs of some plants. But simulations show that the variable exchange rates contribute to costs increases much lower than those of other factors.

[130] Represent size ranges that can be used in the simulation model, not the sizes of the plants in the database

3.10 General lessons learned – Support to non-renewable generation

The analysis of the business cases of different generation technologies allows an approximate assessment of the impact of regulation and policies in the business cases of RET and non-RET plants. Incentives to RET generation are relatively easy to identify: they tend to be visible; in some cases they depend on market-based schemes; and in general are allocated specific budgets. However, evaluating support measures to coal and gas generation more challenging. Many of the provisions that affect non-renewable technologies are either purposefully hidden from view, or quite difficult to track, even for experts:

- Support measures (or incentives) to traditional generation have been provided for a **long period of time.** It is very difficult to pinpoint cause and effect, translating funds used in the past into current costs of generation. For instance, the coal industry has been receiving incentive based support for the best part of a century now. Should those incentives be allocated to current costs? How?
- **Data are not very visible or are not public**. In some cases, support measures to thermal plants are provided off-budget by governments and administrations. Examples include tax alleviation policies in the U.S. and in some European countries[131].
- Support measures to non-RET act **indirectly over the business cases of generation** [132]**.** Therefore, it is difficult to quantify their specific impact on the costs and revenues of a given plant or project. For instance, in 2006 the German coal mining industry received direct financial assistance amounting to €1,700 million. This figure included €1,600 million in grants for the sale of coal for a variety of uses, including electricity generation[133]. The U.S. Energy Information Administration estimates that government incentives to the coal industry amounted to US$3.17 billion in 2007[134]. It is difficult to accurately evaluate how those incentives translate into lower prices of fuel for generation.
- In some cases, measures do not consist of handouts, but of **preferential or singular treatment**. For instance, some coal plants in Germany, Sweden and Spain have allowances that reduce their costs of emissions; or have been exempted from schemes targeting emission reductions. This eliminates up to 10-12% of the potential cost of a coal plant.

However, the background is slowly changing. Governments and private parties concerted efforts are increasing the visibility of support measures. In addition, a growing number of stakeholders are taking measures to control and manage the host of policies that affect and incentivize conventional electricity generation.

- There is an **increased scrutiny** from the public and from public and private institutions that desire to unveil incentives to mining, oil, gas and nuclear facilities. Examples include the recent assessment of the nuclear generation base in France by the *Court des Comptes*, and the U.S. Congress efforts to put a figure on the amounts of incentives that have been devoted to different productive sectors, including energy and electricity.
- There appears to be **higher levels of commitment to reduce at least part of the support to non-RET**, in many cases on environmental grounds. EU directives are forcing some countries to revise their current

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[131] A 2011 report by the OECD concluded that between 2005 and 2010 the 14 leading OECD economies spent up to $75 billion every year subsidizing fossil fuel production and consumption.

[132] The extent in which these incentives to factor cost may have influence the costs of generation is uncertain, but it is very likely they have contributed to enhance the business case of coal generation.

[133] Source: Unweltbundesamt – Environmentally harmful subsidies in Germany (2010 English edition, 2008 German edition)

[134] Source: EIA - The word used in the report is “subsidies”, not policies or support measures

polices supporting the fossil fuel sector. For instance, enacting directives that require reductions of incentives to the coal industry by 2018.

The impact of these measures of support to non-RET generation is difficult to visualize, and calculate. Figure 66 shows an example of how incentives and policies might affect the costs of a coal plant; and compares them with the visible incentives provided to an average on-shore wind plant. The combined effect of grandfathering the plant to previous emission policies (it does not have to pay them); using subsidized coal (or coal with incentives); and adding beneficial tax provisions (3% to income) significant influence the resulting costs of generation. This impact may be significant, but would be hidden from plain view[135].

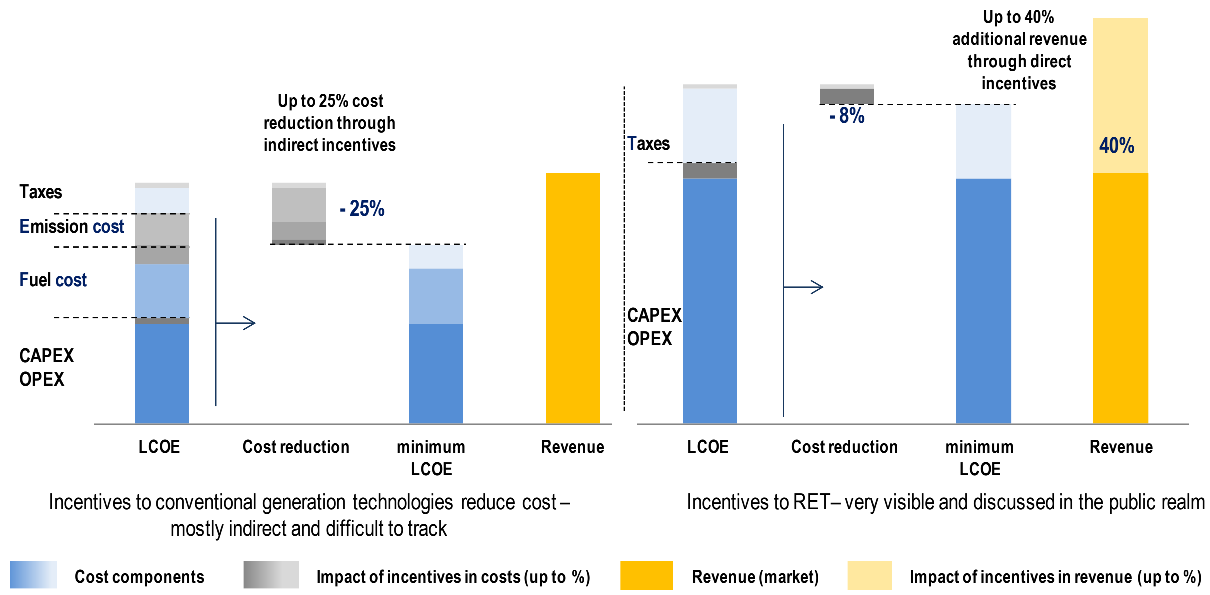


Figure 66. Sensitivity analysis – Comparisons between incentives to coal and on-shore wind (US$/MWh)[136]

[135] For incentive definitions, see Section 7.

[136] Source: PRYSMA analysis. Analyses include data from several countries.

4. LESSONS LEARNED – SUMMARY

The regions and countries in the scope of RE-COST have enacted policies and regulations that directly or indirectly affect the interests of investors in RET and non-RET generation, as well as their appetite to assign funds to a specific project. Policies are often cited as one of the main factors behind the success of RET development. But non-RET plants are also considerably affected by regional and national policies. As a result, there is significant interest by policy makers to evaluate best practices in policy definition, and to assess the potential results of alternative policies.

The analysis of different incentives and support measures in the 7 countries/regions in the scope of this study (see Section 5), and the insights attained from interviews and discussions with actors in the electricity system can be consolidated in a number of general lessons learned to optimize the process of policy making:

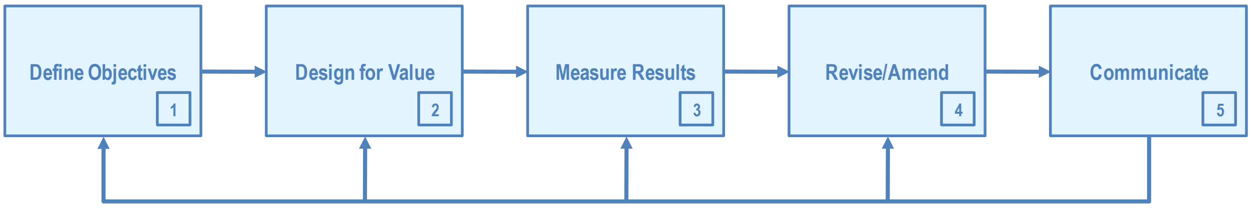


Figure 67. Stages for policy optimization

1. **Define objectives explicitly:** The wording of policies – including laws, decrees, provisions, and other types of policy decisions – should explicitly include the objectives they pursue, not only to justify the policy, but also to provide a framework to evaluate the its degree of success in the future. Examples of explicit definition of policies include the Norwegian and Swedish common goal for their green certificate scheme: "*develop 26.4 TWh of new renewable energy technologies by 2020*". Another example is Ontario's long term energy plan. The development of CCGT seeks to attain measurable objectives: "*Ontario will be coal-free by 2014". "Ontario's target for renewable energy from wind, solar and bioenergy is 10,700 MW by 2018 (excluding hydroelectric)*".

   - **Objectives should include different types of factors:** They could be quantitative (30% of renewable energy by 2020, reduction of current emissions by 20%, etc.); or qualitative (improvement of the technology level of the region A, enhance the capabilities in industrial sector B, preserve jobs in region C, ensure the security of supply, lower costs of generation, etc.). For instance, the German government published in the EEG revision from 2012 new targets of 80% of renewable by 2050 in its energy-mix. The Spanish Renewable Energy Plan (2011-2020) established the objective of reaching 20% of renewable energy in its energy-mix (in terms of primary energy).

   - **Objectives should also be easy to understand and to measure**. For instance if proposing to reduce emissions by a percentage, the basis used should also be explicit (emissions in year 20XX, total amount of emissions, types of emissions). KPIs need to be set at realistic levels and measured regularly to guarantee the success of the objectives.

   - **The objectives of policies affecting non-RET should also be explicit**. As shown in the examples above, many policies addressing the development of RET include at least some reflections on the impact the measures are expected to have on a given set of factors. However, policies that support non-renewable or traditional technologies do not explicitly, or even implicitly, define their objectives. In particular, fiscal measures tend to avoid explaining the specific value sought, for which stakeholders, and why. For example, the Spanish government has recently (2012) introduced a set of fiscal modifications: new income tax (7%) for all technologies operating within the energy sector; a fuel tax (*centimo verde*) for coal and gas-fired plants; an additional tax to hydropower facilities (2.2%-22%); and new taxes for the generation and storage of nuclear wastes. But it has not specifically stated how those measures will eventually benefit consumers and tax payers. In contrast, Norway and Sweden have introduced a tax reduction for on-shore wind "*to enhance the development of this technology*".

2. **Design policies for value and results.** Taking into consideration a number of factors to define electricity related policies may contribute to improve their effectiveness:

- **Keep applying the incentives that have proven to be effective** to develop a generation technology, and which provide reasonable business cases to investors, in so far there is no level playing field between RET and non-RET. Examples of policies that appear to provide interesting business cases to investors include the FITs for on-shore wind in Germany; the offsets scheme in Alberta; the auctions of on-shore wind in Quebec and of off-shore wind in France; the green certificate system for on-shore wind and hydro in Norway and Sweden; and the FIT for solar PV and wind in Japan. To support the deployment of RET it is of particular relevance to maintain priority feed-in in the regions where it exists, such as Spain, France and Germany.

- **Make policies comprehensive.** When defining a policy, it is necessary to evaluate not only its direct impact, but also its ramifications and indirect impact over other stakeholders, and market niches. Contemplating the full supply chain and competitive environment of the electricity sector is not easy to do, but it may contribute to the definition of better balanced policies. For instance, investors in coal and gas plants in France, Germany and Spain claim that their business cases are being damaged by the large development of renewable generation triggered by priority feed-in and other incentives to new RET. It is not clear that policies for RET development have specifically assessed their ultimate impact in other forms of generation, even when these forms of dispatchable generation may be required to ensure the deployment of RET, variable generation.

- **Make policies visible:** Many policies, especially those that affect non-renewable, or traditional generation technologies (coal, gas, or hydro) do not consist on visible funds being passed to suppliers, but on indirect provisions such as preferential treatment, incentives to factor costs, loopholes or exceptions provided to certain plants or sectors, etc (see Section 3.10). Gradually substituting indirect measures of support by direct incentives included in budgets, and with explicit caps may contribute to provide the public with additional tools to evaluate the results of policies. Examples of slight fine-tuning of policies could include:

  - Substitute tax incentives to coal plants everywhere by direct grants that can be measured and assessed by the tax payers, and by electricity consumers.

  - Provide information about the total funds used to fund PPAs in Quebec. This might contribute to a better evaluation and assessment of their impact on the Quebecois electricity sector.

- **Make policies market and operation driven.** In the last two centuries, market defined rules have shown, in general, more resilience than decisions made by a central authority. This is not an absolute rule. Applying strict market rules to generation from new RET would have resulted in a very small penetration of RET everywhere, and to higher levels of emissions. However, since market type structures facilitate the alignment of different requirements in complex environments, adding the invisible hand to the definition of policies may contribute to strengthen them. Examples of market driven policies include the green certificates in Norway /Sweden. Examples of operationally driven policies are the Chabot schemes[137] (Denmark and Germany) for FIT that benefit technologies based on the highest quality of resources.

[137] The "Chabot Method" defines a FIT based on a "profitability index" equal to the net present value of the cash flows of the project divided by the present value of the total installed cost. The Chabot method defines a system of tariffs that may increase or decrease the returns obtained by producers according to elements such as the quality of the wind in one site or another. Projects in sites with better wind quality have an advantage over those located in places with lower wind quality.

Mixed policies – policies based on market and operational provisions – may simultaneously incentivize the development of a technology, and maintain a degree of competition. For example, Germany has introduced several requirements for wind generation to obtain longer initial FIT payments by connecting those payments to plant location, commissioning date, operation period and reference yield to calculate tariffs after time. In addition, Germany has defined a marketing premium scheme that includes market pricing elements in the revenues attained by eligible plants.

- **Establish limits or caps for the policies.** In particular, define limits for the total amounts of (public) funds that are going to be devoted to a specific policy. Several of the policies examined in this study contain time-related clauses: provisions are valid only for 10, 15, or 20 years; FIT in Germany are paid for 20 years plus the starting year of operation; Norwegian and Swedish green certificates will support renewable technologies for 15 years or until 2035, whichever ends first; etc. However, time based policies may not be enough to prevent funds reaching excessive values not intended by policy makers. For instance, the past generous incentives awarded in Spain to RET have resulted in larger than expected public funds being paid to investors in RET. Adding a cap upfront could have reduced the need to define retroactive measures to rein-in public expenditures tied to incentives to development of renewable technologies.

- **Have the consumer pay for the policy.** In some cases electricity policies are partially funded by the state; that is, by the taxpayer. This dilutes their visibility and makes them more difficult to track by the public. In contrast, when the consumer sees the impact of a policy in his power bill, he is better able to evaluate its convenience and value. Examples of payments visible to consumers include (1) green incentives, where the electricity consumer pays a mark-up due to the scheme, (2) the German electricity bill, where the costs of renewable energy development are displayed by a surcharge or special tax (EEG-Zuschlag), which is directly passed onto consumers.

- **Reduce the exceptions in the policies.** Provisions that limit the applicability of the policies to a narrow set of situations (sectors, plants, types of providers, etc.) should be limited. Exceptions increase the complexity of policies; make it more difficult to track their true impact; tend to stay forever, even after they are necessary; and may produce unintended results, such as technologies with large amounts of emissions (coal) being supported at the expense of other, less polluting alternatives (gas).

3. **Measure the results of policies.** It would be highly recommendable that, as a matter of course, policy makers conduct and publish explicit analyses of the results of policies, at least before substituting a policy by another, and after cancelling a policy. For instance, state or national plans for RET development in several of the regions in scope include some assessments of the results obtained by the previous version of the plan. Energy development plans for 2030 mention the extent of progress made in the implementation of 2020 targets, and the reasons for the deviations observed. However, this best practice is not always followed. It would be necessary to reinforce some mechanisms to enable the accurate measure of the impact of RET development policies in particular, and of policies applicable to the electricity sector in general. Examples of measures that would contribute to the accurate assessment and publication of the results of policies include:

    - **Make compulsory the sharing of information** to the parties benefited by a given policy, especially if large funds are involved, or if the funds are provided by taxpayers. At the present there is a large imbalance in the quality and amount of information that some parties who benefit from policies have (e.g. large utilities, plant developers, etc.), and the accuracy of the information managed by policy makers. Establishing provisions that encourage owners of plants that receive incentives to share real data would contribute to fine-tune the details of future policies.

    - **Provide adequate resources (tools and capabilities) to policy makers to evaluate results and optimize policies.** Usually the funds available to the public institutions that craft policies are much more reduced than the funds available to the public and private enterprises that benefit from them. As a consequence, recipients of incentives are much better equipped to evaluate the ultimate impact of policies and to lobby for policies that benefit them. It would be recommendable that a fraction of all the funds devoted to supporting and incentivizing the electricity sector was explicitly allocated to institutions with the specific charter of revising the policies that have determined these funds. This would ensure that the manpower and analytical tools available to policy makers are sufficient to optimize policies. In particular, providing policy makers with updated tools and knowledge comparable to those available to utilities, developers, and investors might contribute to the definition of better balanced policies.

4. **Revise and amend policies:** Policies should include provisions that enable their amendment, and that adjust them when circumstances change. This flexibility has to be balanced with the need to provide stakeholders and investors with stable measures and guidance.

   - **Make policies adaptable:** Typical policies commit to actions during relatively large spans of time. This provides assurances to investors and reduces their risk levels. However, in the time span in which the policy applies (10-20 years), the circumstances of the recipients and of their environment may significantly change. Adding clauses that adapt the value of the incentive to evolving levels of costs, technology developments, inflation, factor costs, etc. still provides significant assurance to investors, and reduces the risk of obsolete policies. Examples of adaptable policies include (1) France's remuneration model for renewable energy, which includes a partial adjustment of FIT payments by inflation (40% of the FIT is not adjusted); (2) the German EEG, which establishes a degression of FIT payments to represent the technological and operational advancement in this technology (1.5% annual for on-shore wind, starting in 2013).

   - **Make policies stable.** Retroactive or tentative policies should be avoided whenever possible. Examples of retroactive policies include those that unexpectedly reduce the compensation of existing plants; policies that do not include clear quantitative measures of the incentives provided; provisions that make existing policies void (reducing excessively the budget allocated to the implementation of a policy). For example, the Spanish Government has recently suspended the incentives for new renewable energy projects. In addition, the market premium option has been canceled, and the time of operation eligible for FIT remuneration has been limited for existing plants. This lack of policy stability is significantly increasing the challenges of investors in RET in Spain.

5. **Communicate and share information.** The extent and depth of information provided by policy makers in the countries analyzed is very different. Some policies are very opaque, and consist of decisions that do not explain their rationale or the expected results. Other policies include a variety of information channels for different types of stakeholders: the public, suppliers, consumers of electricity, etc. Communication is an important factor to optimize policies, and to obtain support for them. Examples of different communication practices and vehicles include:

   - **Define information channels** to ensure communication with different types of stakeholders, and to tailor the information provided to specific audiences. The German Bundesnetzagentur, entity responsible for grid development, publishes on its website on a monthly basis the management premium payable to renewable energy plants under the market premium scheme. Stattnet in Norway and Svenska Kraftnät in Sweden display contract prices for green certificates on a daily basis.

   - **Ensure consultation with the sector.** Defining channels to incorporate the views of stakeholders may contribute to optimal policies. Different points of view may enrich the processes of policy revision and amendment. Defining a variety of channels to access opinions and data is critical to ensure that the resulting policy is non-partisan and is balanced. Fostering the interactions between public institutions and private companies is of particular importance to ensure that policies are not defined in an ivory tower.

PART 2

5. GENERATION TECHNOLOGIES – FACTORS AND COSTS

It is critical for policy makers to have accurate, up-to-date understanding of the costs of generation of each technology, and how they are evolving. This section provides a summary of the characteristics of the technologies included in the scope of RE-COST[138], and of the trends that are contributing to change the costs of generation over time. The results shown are based on the data contained in the database that has been built for this study[139].

On-shore wind	• Only utility scale generation plants are included (larger than 2 MW). • In some cases where the construction of new renewable plants has been almost stopped in the last two years (Spain) some 2008-2009 projects have been included in the analysis.
Off-shore wind	• The analysis focuses on plants and projects from 5 countries (France, Germany, Norway, Sweden and Japan). • Data from operating plants and development projects have been complemented with data from publications, and with information from projects in other countries (e.g., UK).
Large solar PV	• Only ground-mount, larger than 1 MW plants are considered. Excluded from the analysis are roof-top, domestic and small-scale plants. • Only solar photovoltaic plants are included. Thermo-solar plants are not in the scope of the study.
Hydro	• A small number of hydro plants have also been analyzed (Ontario, Quebec, Germany, Norway and Japan in order to present a benchmark of costs in regions where hydro generation is of capital importance.
CCGT	• Especial effort has been made to obtain data from new gas-fired plants, with a special focus on the new designs that optimize operation and costs with low capacity factors. • Plants of different configurations (different number of turbines) are included. This may contribute to increase the ranges of cost results, but the impact is much less important than that of other factors such as gas prices, and capacity factors.
Coal	• Only new designs based on supercritical, pulverized coal are included in the analysis.

Figure 68. Focus of analysis – Technologies included in the database of plants and projects

5.1 On-shore wind – Cost of generation

Today more than 55,000 wind turbines are installed in the world, accounting for approximately 237 GW of power capacity[140]. Figure 69 displays the electricity produced, and the proportion of generation capacity that on-shore and off-shore wind generation represented in 2011 in the regions and countries in the scope of this study.

[138] Hydro is not analyzed in detail, having been used as a reference only. Therefore, the accuracy of the data and associated analyses for hydro generation is lower than that of other technologies.

[139] Although the bulk of the assessment considers just new plants and projects, this requirement has been relaxed in some cases in order to confirm some of the insights attained. Data from older plants from PRYSMA databases and publications have also been used.

[140] Source: WWEA - World Wind Energy Report 2011

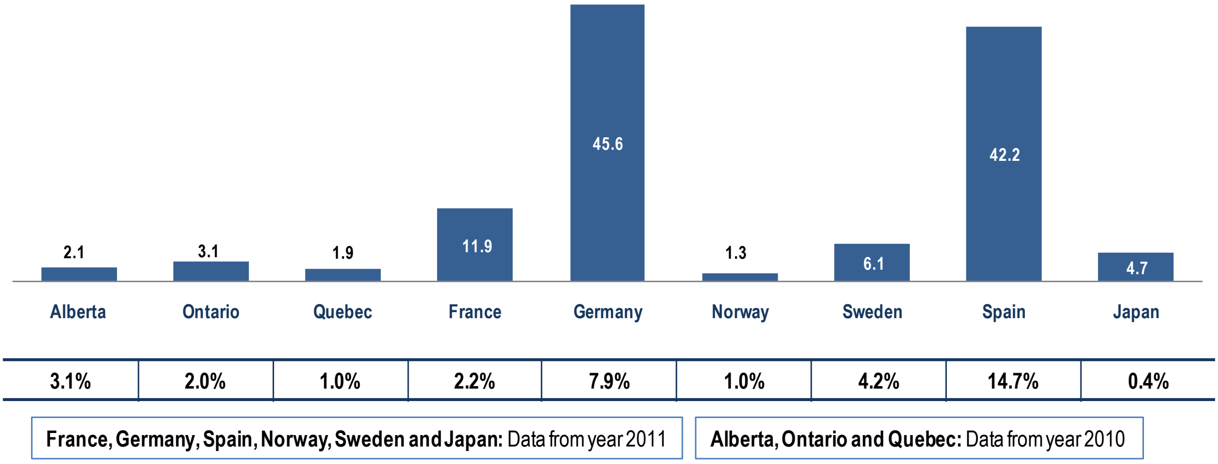


Figure 69. On & off-shore wind generation (TWh) per country and percentage of total generation[141]

Capital costs of on-shore wind plants result from the build-up of the costs of a number of components. As discussed in Section 2.5.2, there is no standard method to group and report the key components of capital costs. Each of the participants in RE-COST provided a distinctive cost breakdown. The raw data were standardized to make the simulation model manageable, and to enable comparisons of data obtained from different actors, and of plants operating under diverse situations. Figure 70 shows examples of capital cost breakdowns of wind turbine costs obtained from publications[142], as well as the standard breakdown of capital costs of wind plants used in this study.

EXAMPLE[143]	Share of total cost %
Turbine (ex works)	**68-84 %**
Grid connection	2-10%
Foundation	1-9%
Land rent	1-5%
Electric installation	1-9%
Consultancy	1-3%
Financial costs	1-5%
Road construction	1-5%
TOTAL CAPITAL COSTS	**100%**

STANDARD[144]	Share of total cost %	
Turbine	**41%**	
Foundation	12%	
Electric installation	9%	
Indirect	7%	EPC COST = 69%
Land cost	2%	
Pre-financial costs	7%	
Grid infrastructures	11%	
Spare parts	4%	
Project Mgmt. and others	4%	OWNER COST = 26%
Contingencies	5%	CONT. = 5%
TOTAL CAPITAL COSTS	**100%**	**100%**

Figure 70. Breakdown of capital costs of on-shore wind

The costs of wind generation depend on a large number of factors. Effective policies must take into account their impact and evolution:

1. Technical or technology costs consist of the costs of each of the components of the wind plant. As shown in Figure 70, the most important cost item is the wind turbine, which represents between 41-84% of the total capital costs of an on-shore wind plant. Over time, the effectiveness of turbines has increased, and their prices have

[141] Source: Data extracted from the summary in Figure 98. Data represent on-shore and off-shore generation.
[142] Source: IEA Wind Task 26
[143] Source: The Economics of Wind Energy, EWEA Report 2009
[144] Source: Prysma analysis

decreased, as depicted in Figure 71. This has translated into a gradual reduction of the costs of on-shore wind generation.

Accurately gauging the size and speed of this reduction is critical for policy makers, who must define incentive schemes high enough to interest investors, and low enough to prevent windfall profits.

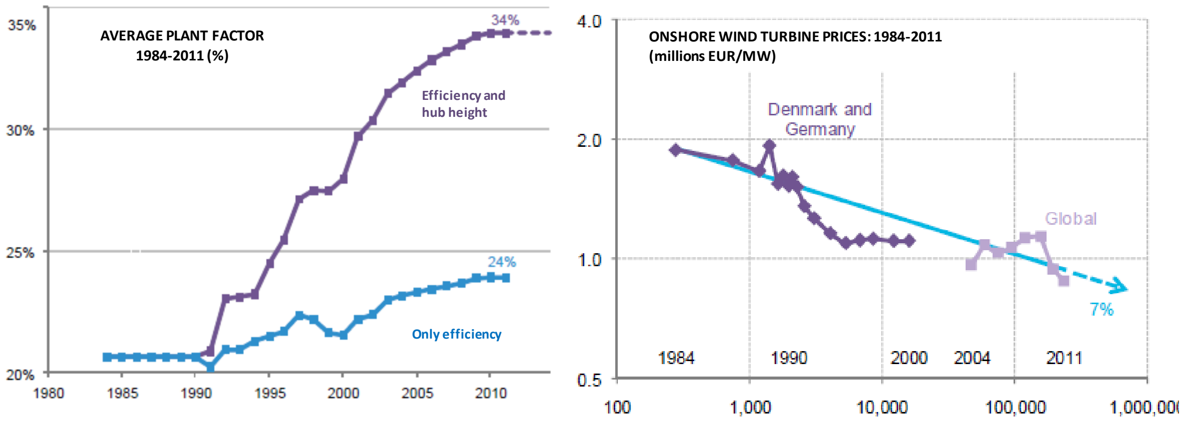


Figure 71. Wind generation - Impact of height in turbine efficiency and evolution of turbine prices[145]

2. Market forces. Figure 72 displays the results of a recent study by Berkley Labs, based on data from Vestas for the United States market. The graph shows the evolution of turbine prices from 1997 to 2011. Also represented is the range of turbine prices of new plants obtained from interviews in the framework of RE-COST (950 -1050 US$/MW).

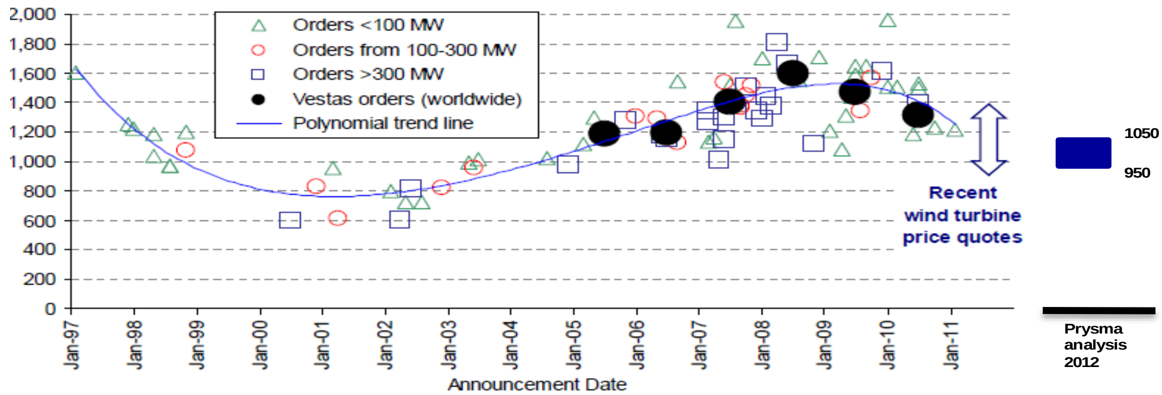


Figure 72. Evolution of prices of turbines (2010 constant US$)[146]

Brisk demand of new wind plants from 2002 to 2008 is considered one of the most important factors behind the increase of up to 50% in the worldwide prices of turbines. Manufacturers were able to set up higher price points in a seller market. The onset of the financial crisis, and the associated reduction in demand have triggered the opposite effect. In 2011-2012, manufacturers have been willing to heavily discount their products because of operating and financial reasons (to eliminate backlogs), or due to strategic reasons (to step over a competitor or to win market share).

[145] Source: GAMESA – Public report: 2011 - "La energía eólica – la enegia líder" – Data from Bloomberg

[146] Source: Berkeley Lab, Vestas (2011b, 2011c, 2011d), Bloomberg NEF (2011b), as depicted in NREL "analysis of Wind Power costs 2011"

Investors and developers are expressing concern that drastic cost cutting might result in significant problems for manufacturers and developers of wind farms. Most of them may not be able to maintain such low costs in the future. This would apply not only to the new Asian entrants, but also to established turbine manufacturers that may be quoting aggressively low prices today, which in the long term they will have difficulties sustaining.

The degression rates and reductions over time of some of the incentives applicable to wind generation, for instance the FITs in Germany and France, assume a continuous reduction of generation costs that may not fully materialize in the medium term. It is necessary that policy makers maintain a close watch over the evolution of the market, and its impact on the costs of turbines and other components of wind plants, to ensure optimal alignment of future policies.

3. Location-dependent costs. Costs of materials and labor depend to a certain extent on the country, province, or specific location in which the wind farm is located. Factors such as, union agreements, availability of materials, import taxes, and others influence the cost of labor and the cost of the components of a wind generator. However, wind generation is increasingly becoming a global industry. The differences between the costs of wind in different countries are gradually decreasing.

Databases and analyses that lump together data from several regions and countries must not accurately depict regional characteristics that may be understood in order to optimize the definition of regional or national policies. It is necessary to develop regional/country specific databases to ensure that local policies are optimal.

4. Learning curves. Increasing experience with wind generation is contributing to drive down some costs over time. New plants display lower costs than older plants. For instance, operation and maintenance (O&M) costs have decreased from average 50€/MWh (65 US$/MWh) in the 80s, to less than 15 €/MWh (19.5 US$/MWh)[147] today. More reliable equipment, design for maintainability, and a steep learning curve of operators and maintainers have contributed to this reduction

Further cost reductions from learning and experience are possible, but data and interviews suggest that the learning curve of on-shore wind generation may be starting to plateau. This would be consistent with the trends observed in the learning curves of highly engineered products (trains, aircraft, cars, etc.) Once a technology reaches maturity, slower cost reductions of O&M costs should be expected. This has to be taken into account by policy makers when defining degressions and variations of incentives for wind plants.

5. Obsolescence: Experience with a specific plant is likely to contribute to a reduction of O&M costs after the first years of operation. However, the typical cost curve may behave as indicated in Figure 73.

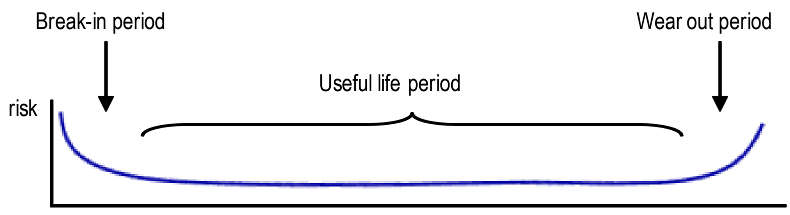


Figure 73. Maintenance risk and costs – patterns of evolution over life-time[148]

[147] Source: Interviews

[148] PRYSMA analysis and experience

The initial, relative high costs of maintenance may decrease over time, as operators and crews get acquainted with the equipment. However, after 10-12 years, maintenance costs increase again because of equipment obsolescence. This increase may be relevant for the future operating costs of plants, but may not be taken into account in the incentive schemes for wind generation in the countries in scope of the study, which mostly assume linear reductions of costs over time

5. Supply chain structure. Another important factor that affects O&M costs is the type of contract defined between the operator and the maintenance provider. In many plants, during the he first 1-3 years of operation, operation and maintenance are covered by a guarantee agreement between the operator and the original equipment manufacturer (OEM). Once the guarantee expires, operators may hire third party providers, not necessarily associated to the manufacturer, to take responsibility for O&M, for instance, local crews with lower hourly rates than those of the OEM. This may create additional downward pressure on the total costs of operation and maintenance of wind turbines. But if there are provisions that limit the freedom of operators to choose maintenance providers – for instance, when incentives are tied to the usage of local labor, or SMEs – operators may not be able to effect reductions in O&M costs as significant as they would otherwise.

6. Repowering. In a number of cases it may be more advantageous for the business case of an investor, to repower an established wind plant – substitute the old turbines by new, more cost-effective ones in a location with good wind characteristics – than to install a new plant in another location. The database of plants of RE-COST does not include any instance of plant repowering. Therefore, repowering has not been simulated. However, as more plants are repowered, it is to be expected that there will be enough data to evaluate in-depth the costs associated with repowering. In some schemes, for instance in Spain, the incentive is modified or lost if the plant is repowered. This may limit the ability of the investor to optimize costs and improve its business case.

Figure 74 shows a comparison of the costs of generation for on-shore wind (LCOE) for the regions/countries in the scope of RE-COST, using new plants and projects as a basis. A number of factors contribute to the similarities and to the differences observed in the costs of generation of similar plants operating in different regions.

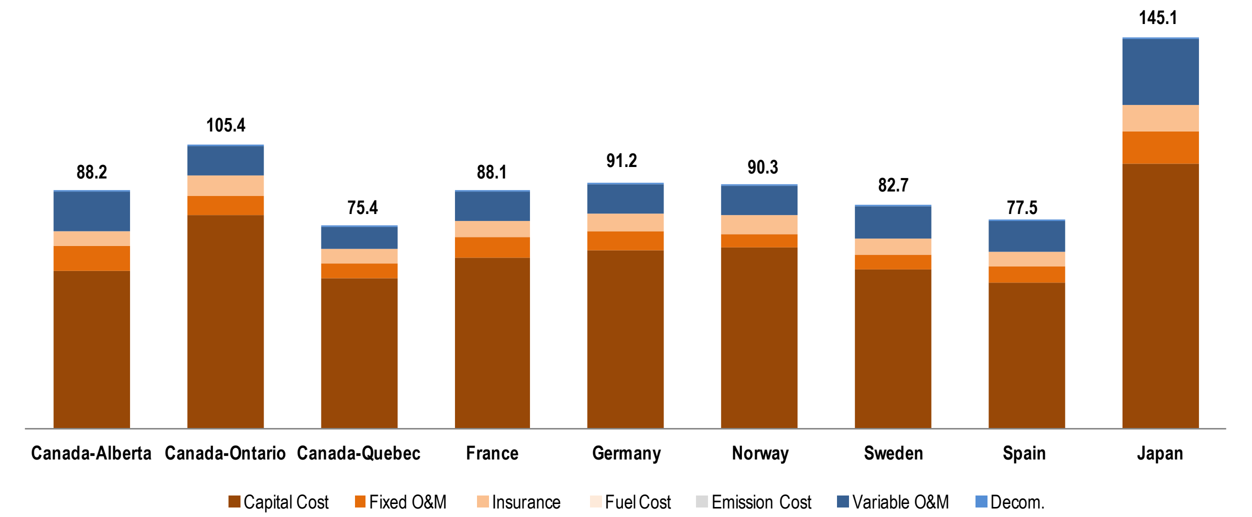


***Figure 74. LCOE on-shore wind by country (US$/MWh)*[149]**

- **Global Procurement:** Costs of wind generation are similar within Europe, even when comparing countries with different labor rates, land costs and other factor costs. This reflects the convergence of prices in the EU. Actors and experts coincide in stating that, everything else being equal, the costs of any technology

[149] Source: Prysma analysis. Model results for an example plant: size = 70 MW in Alberta, 100 MW in Ontario and Quebec, and 50 MW in other regions; capacity factor = 30%; discount rate = 5%.

will show relatively small differences in Europe, since suppliers of turbines and other key equipment are global, and tend to quote prices for their equipment by continent.

- **Country specific factors:** Each country has specific factors that affect the business cases of generation plants. A full analysis of these factors is outside the scope of RE-COST. However, policy makers need to understand the sources of differences between plants of different countries in order to craft optimal policies for their specific regions. Examples include:
  - The impact of construction regulations for earthquake prevention, high costs of transmission, and the fragmentation of the Japanese electricity market in areas with incumbent suppliers may be contributing to increase the costs of generation in Japan.
  - Long distances in Norway, Sweden, and Canada result in higher costs of connection to the grid (included in capital costs)[150].
  - Some of the best locations for on-shore wind in Germany are already taken[151]. This may reduce the utilization of some new plants.
- **Impact of competition:** Competition against other suppliers may affect the capital costs of on-shore plants quoted by manufacturers and suppliers. For instance, it has been suggested that competitive auctions may contribute to reduce the costs of on-shore wind in Quebec. In the recent past, Quebec has used Requests for Proposals (RFPs) to incentivize and enable on-shore wind, in a hydro-driven market, with very low electricity prices. There have been three RFPs in 2005, 2008 and 2010 that have resulted in long-term Power Purchase Agreements (PPAs) between producers and the incumbent utility, Hydro-Quebec. Concurring to a competitive RFP may result in a reduction of quoted costs of generation because companies try to outbid each other.

Figure 75 shows ranges of costs and revenues of on-shore wind generation in the regions in the scope of the analysis.

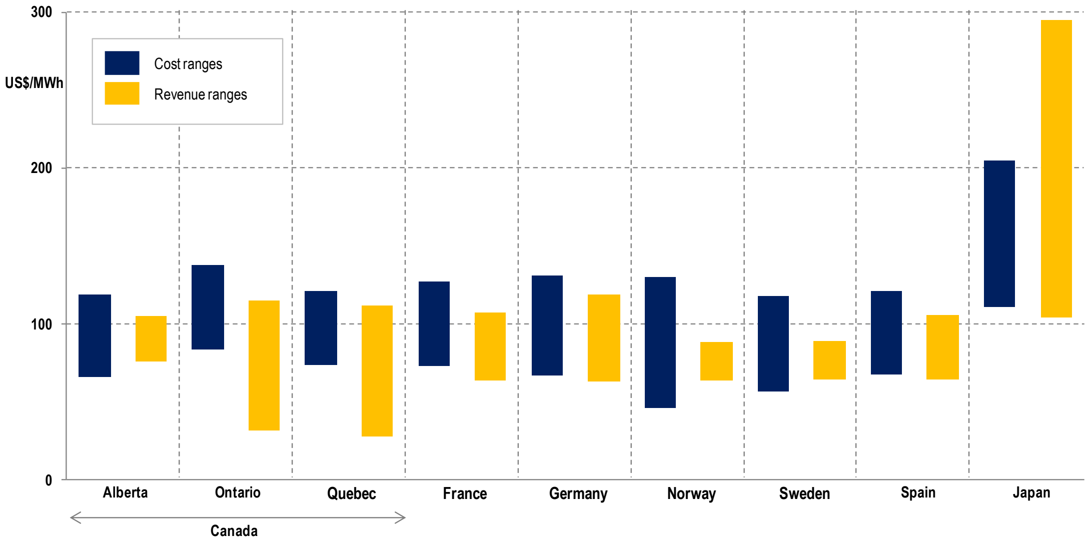


Figure 75. On-shore wind – LCOEs and revenues of different countries (US$/MWh) [152]

[150] Transmission costs are also affected.

[151] As discussed previously, this issue may be circumvented by repowering an older plant. This decision must be balanced against the impact that repowering may have in the business case of the repowered plant.

[152] Source: Prysma analysis. See section 5 for details.

5.2 Off-shore wind – Cost of generation

At the end of 2012, there were 18 operational off-shore wind plants, 27 projects under construction, and many more in permitting or planning process[153] in the regions/countries in the scope of this study.

Figure 76 shows a comparison of LCOE of off-shore wind obtained from the RE-COST database of projects. Many of characteristics and behavior of off-shore wind plants are similar to those of on-shore wind plants. However, there are specific factors that influence the behavior of costs of generation of off-shore wind.

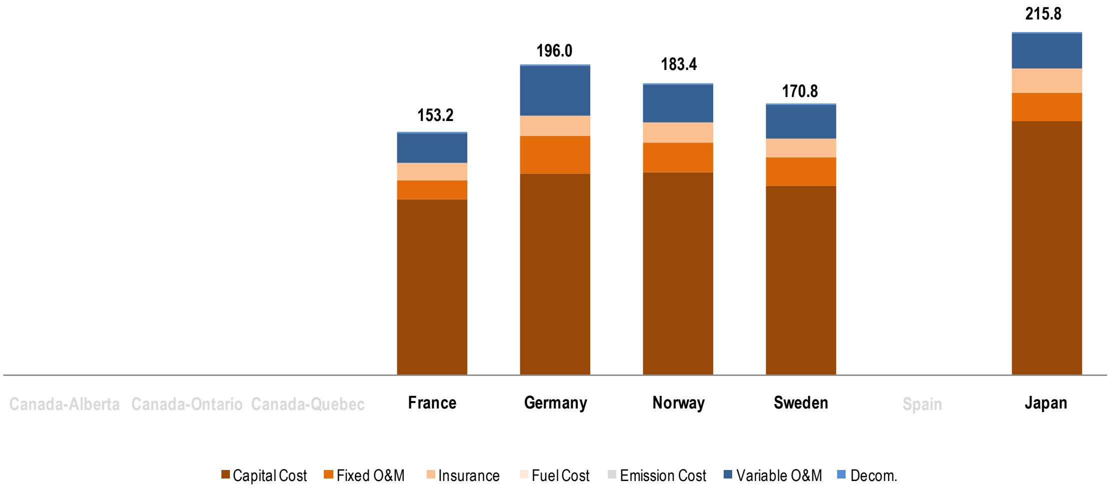


Figure 76. LCOE Off-shore wind by country (US$/MWh)[154]

1. Complexity. Developers of off-shore wind plants face significant and specific challenges: minimize the impact on the environment, avoid competition with other dependents of the sea (transportation, fishing, tourism, etc.), secure access to the national grid at a reasonable cost, etc. The challenges associated to building and operating off-shore increase the costs of generation through two mechanisms: directly, increasing the costs of building, operating and maintaining the equipment; and indirectly, increasing the financing ratios of off-shore wind projects.

2. Risks of off-shore technologies. In general, off-shore wind developments have higher levels of uncertainty than on-shore wind plants. Even projects that appear to be on track may suffer delays, and accrue higher costs than expected due to factors that not are always predictable[155]. Understanding the sources of risk and the potential impact on each off-shore project is critical to define technology-specific policies.

3. Lower levels of data accuracy. Special care has to be applied when evaluating the results obtained from the analyses of on-shore wind plants. Data and information available for this technology show high levels of technical, financial, and policy uncertainty. As a consequence, in a number of cases the data gathered from off-shore wind plants have been defined by their sources as preliminary or tentative[156].

[153] Source: 4c-offshore – project database accessed on 23.10.2012, Prysma analysis. Please note that some countries may not have yet operating off-shore wind plants. However, since projects are also included in the RE-COST database, results are shown for countries where plants are only in the concept or early planning process (e.g. Norway), that does not have operating off-shore wind plants, or Japan, where most operating off-shore wind plants are demonstration units or are very small.

[154] Source: Prysma analysis. Model data from an example plant. (Size 150 MW (France 600 MW), capacity factor 40% and discount rate 5%).

[155] For instance, in October 23rd, 2012 it was announced that DONG Energy had decided to shelve the Borkum Riffgrund 2 off-shore park (Germany)[155]. The reason provided by DONG was that the transmission network operator had not been able to provide a date for when the off-shore cables would be laid.

[156] Source: interviews carried out in the framework of the RE-COST Study.

- In some cases, **the plants in the database are just projects**. Actual costs are expected to somewhat differ from projected costs.
- **Steep learning curves** are contributing to decrease the costs of plants in operation. In the future O&M costs of off-shore wind may significantly decrease. But it is not clear which values they will reach, and when.
- The **different technologies and configurations** of supply chains used in off-shore wind construction and operation difficult narrowing down costs over the lifetime of the plant.

To enhance the quality and accuracy of the results, cost and performance data have been complemented with qualitative information obtained from expert interviews, and with data from publications and recent analyses. Figure 77 shows ranges of costs (LCOE) and revenues of off-shore wind generation in the regions in the scope of the analysis, obtained from simulations of the RE-COST database of off-shore projects. Ranges of costs and differences between countries reflect the high variability in terms of location, size, and capacity factors.

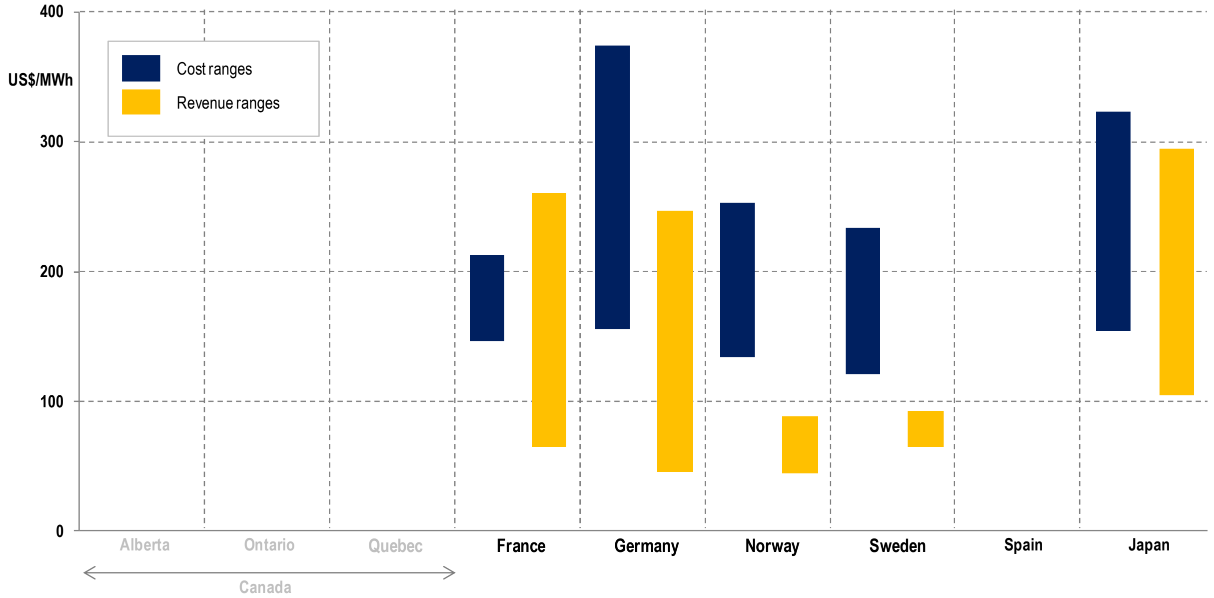


Figure 77. Off-shore wind – LCOEs and revenues of different countries (US$/MWh)[157]

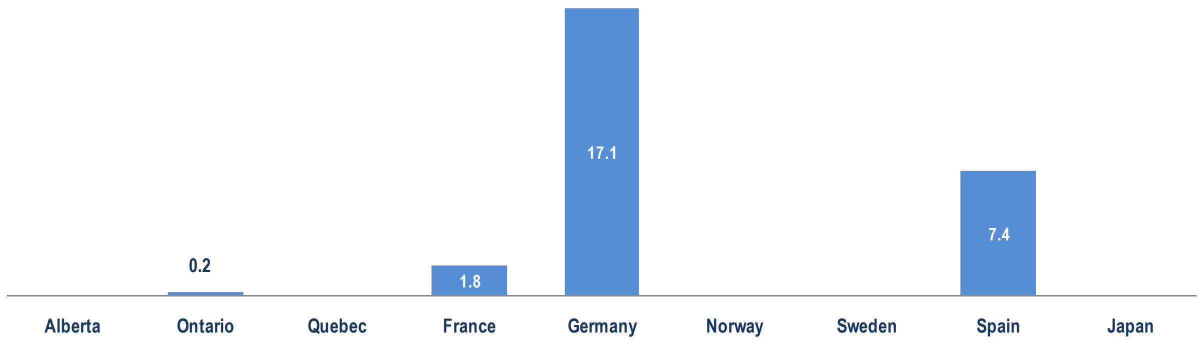
Policies that support off-shore wind generation should be specific. They must respond not only to higher cost of generation, but also to the significant variability and uncertainty associated to this technology.

5.3 Solar PV – Cost of generation

Prior to the 90s, solar installations were off-grid systems used as a source of back-up power by industries and households. In the 90s this situation started to change. Increasingly larger solar systems were connected to the grid, becoming commercial sources of power.

FIT and other incentives have proven to be powerful tools to stimulate solar as a source of power generation. The boom of solar generation has resulted in enormous global growth: from 0.5 MW in 1981, to 27,700 MW of total installed capacity in 2011, representing 43% compound annual growth. Figure 78 displays the total installed capacity of solar PV plants, and the proportion they represent of annual generation in the countries in scope.

[157] Source: Prysma analysis. LCOE breakdown and business cases in Section 5



0%	0.1%	N/R	0.3%	3.0%	N/R	N/R	2.6%	N/R

France, Germany, Spain, Norway, Sweden and Japan: Data from year 2011 **Alberta, Ontario and Quebec:** Data from year 2010

Figure 78. Solar PV generation (TWh) per country and percentage of total generation[158]

This significant growth has come at a price. A combination of high levels of compensation for solar electricity; lax regulations about installed capacity; and the obligation to purchase the electricity produced have resulted in large amounts of public and private funds being devoted to pay for solar power. This situation has driven many countries to severely curtail incentives: Spain (2008 + a moratorium in 2012), Germany (2009-2012), the Czech Republic (2010), France (2010- 2011), Italy (2011-2012) and the UK (2011-2012). These decisions have generated industry protests, and have caused significant uncertainty in the sector. Some investors and developers fear now that some of the tariffs may be retroactive in certain countries[159].

The costs of a solar PV plant include all the outlays during its lifetime, for example, investment costs – construction and commissioning; costs of operation and maintenance – including the margins of third party providers when applicable; the cost of replacing inverters (the lifetime of inverters is shorter than that of PV modules); land costs (for large-scale ground-mounted systems only); cost of take-back and recycling the PV system at the end of its lifetime (decommissioning), and others [160]. Figure 79 shows the breakdown of capital costs of a typical solar PV plant.

Breakdown of solar PV capital costs	Share of total cost %
• PV Modules (incl. Transport)	50 %
• Electrical Engineering – supply (inc. grid infrastructure.)	18%
• Mechanical Engineering	15%
• Civil Works	6%
• Electrical Engineering - installation	4%
• Site Security	2%
• Site facilities and control offices	2%
• Compensatory measures and insurance	1%
• Preparatory works	1%
TOTAL CAPITAL COSTS	**100%**

Figure 79. Breakdown of solar park construction costs – 2012[161]

Figure 80 shows a comparison between the costs of generation of solar PV obtained in the different regions/countries in the scope of this study.

[158] Data extracted from the summary in Figure 98.

[159] Example: Spain. Source: EPIA 2012, Ministerio de Industria.

[160] Sources: EPIA, "Solar Photovoltaic – competing in the energy sector"; Prysma interviews and analysis.

[161] Source: Data from interviews, Prysma analysis.

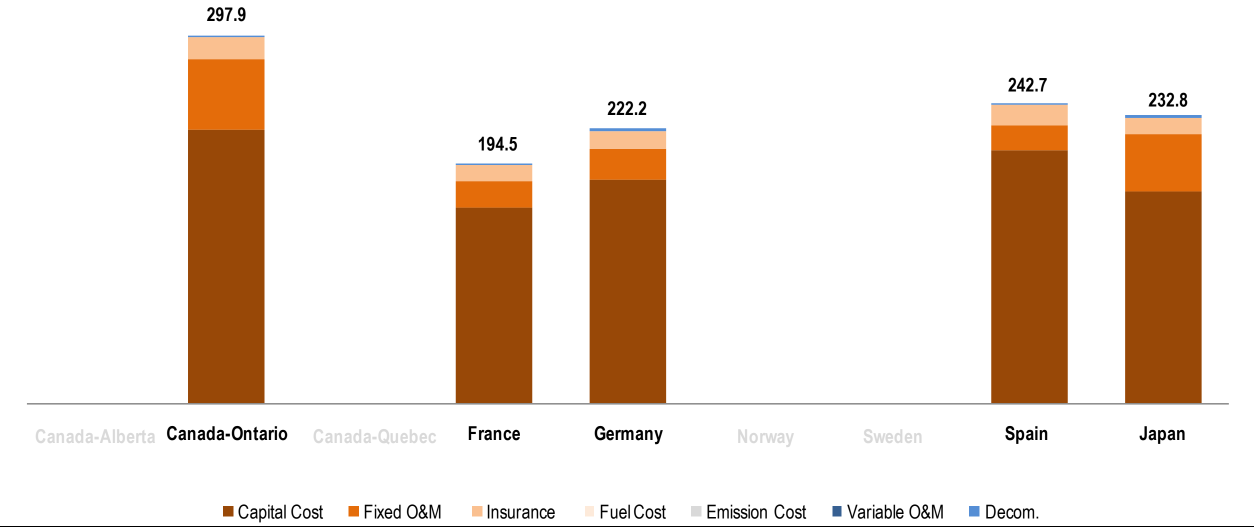


Figure 80. LCOE solar PV by country (US$/MWh)[162]

Capital costs of solar plants have been significantly decreasing in the last years. Reductions of 18-22% per year have been described in interviews and sector publications. Factors that are contributing to the gradual reduction of the costs of solar PV generation include:

1. Reductions of prices of modules. Modules represent ~45-60% of the capital costs of a solar PV plant. Module prices have been dropping considerably in the last years due to improved industrialization, vertical integration of manufacturing, increased scale, and – as contended by some actors, but not conclusively proven – through commercial dumping of components by certain manufacturers. Module prices were on average ~85 US¢/Watt at the beginning of 2012. Data from publications and interviews with actors in the solar PV sector have highlighted significant and continuous reductions of module prices during the elaboration of the report. At the beginning of 2013, module prices are in the range of 50-60 US$¢/Watt. Incentives to generation must take into account this situation to fairly reward solar PV generation, whose costs may be changing not for every year, but from quarter to quarter.

2. Reduction of the prices of other components of solar arrays is also expected in the short term. Many actors in the supply chain of solar PV components are increasing the efficiency of their operations. Larger operations scale, increased industrialization of component manufacturing, and process improvements are reducing the unit costs of manufacturers of inverters, controllers, and other ancillary devices. These factors are likely to result in additional capital cost reductions in the short term.

3. Financing and capital requirements: Solar PV generation is highly capital intensive. This fact is sometimes overlooked because solar PV plants tend to be small in comparison with those of other generation technologies. As a consequence, building utility sized solar PV plants requires mobilizing significant amounts of capital in comparison with the size of expected returns. The ability to line up sources of financing at reasonable (low) rates is critical to ensure the viability and ultimate success of a solar PV plant. Any policy measures that reduce the risks of developers, and therefore, allow them to operate with lower discount rates, are likely to significantly affect the development of solar PV.

4. Market dynamics: The solar PV industry appears to be in the midst of a commodity trap. That is, some of the segments of the supply chain are occupied by many companies, which fiercely compete to sell products which are increasingly seen as commodities.

[162] Source: Prysma Analysis. Model data from an example plant. (8 MW, capacity factor 25% and discount rate 5%).

As depicted in Figure 81, the center of the supply chain of solar PV is occupied by about 1,200 companies which manufacture PV products worldwide (PV cells, modules, systems, etc.). But the extremes of the supply chain are quite consolidated. 90% of the basic material (polysilicon) is produced by a few companies, most of them based in the United States, Japan, Europe and China[163]. Also, at the onset of solar PV generation, several hundred companies were building solar systems. But in the last two decades furious competition and cost cutting have driven many of the contestants out, leaving only a handful of large, integrated companies, located in low labor cost countries (Korea, China, etc.) that build PV systems. These companies could maintain the low prices seen today and still reap benefits.

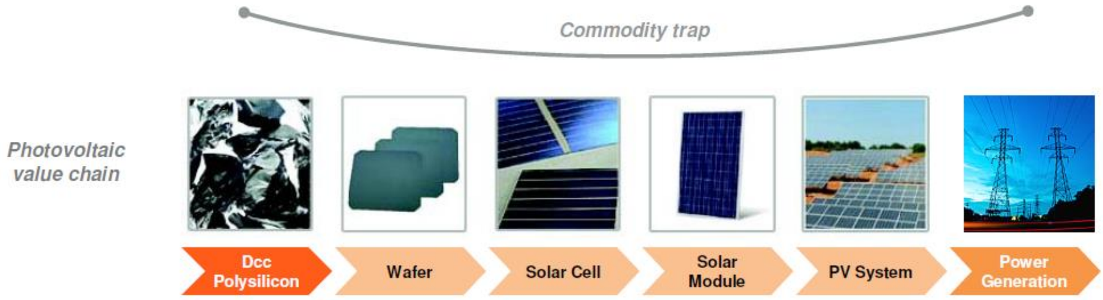


Figure 81. Illustrative – The commodity trap in the photovoltaic value chain[164]

This situation introduces additional factors that have to be considered by policy makers. Examples of questions that must be answered when defining optimal incentives and support for solar PV plants include: to which extent will new solar PV plants contribute to foster employment in the countries where power is generated?; what is the likelihood that companies that receive public funds will stay in business long enough to repay them?; are funds earmarked to stimulate local R&D ending up in the P&Ls of foreign investors?; etc. A better understanding of the quickly evolving market dynamics of solar PV is essential to define optimal levels of incentives, and to ensure they reach the desired recipients.

Figure 82 shows ranges of costs and revenues of solar PV generation in the regions in the scope of the analysis. A number of insights may be extracted of from their analysis:

Costs of solar PV show large variations. The ranges of generation costs of solar PV are very high. Evaluating plants operating in the same region, and limiting the analysis to narrow ranges of installed capacity reduce the cost ranges. Still, the large ranges of costs shown in Figure 82 reflect the significant differences in the configuration and characteristics of the plants included in the database:

- **Solar modules** costs have significantly change in the last years. Plants with similar configuration, but commissioned two years apart, may show noticeable differences in module cost, and as a result, in their costs of generation.
- The cost of **other components** may also be quite different. For example, costs of electrical engineering or mechanical engineering significantly differ across the database of plants, and contribute to increase the ranges of costs.

[163] Source: IEA. ETSAP. Photovoltaic Solar Power, The solar Industry. Silicon Valley Bank. March 2012.
[164] Source: Solar PV Company "confidential"

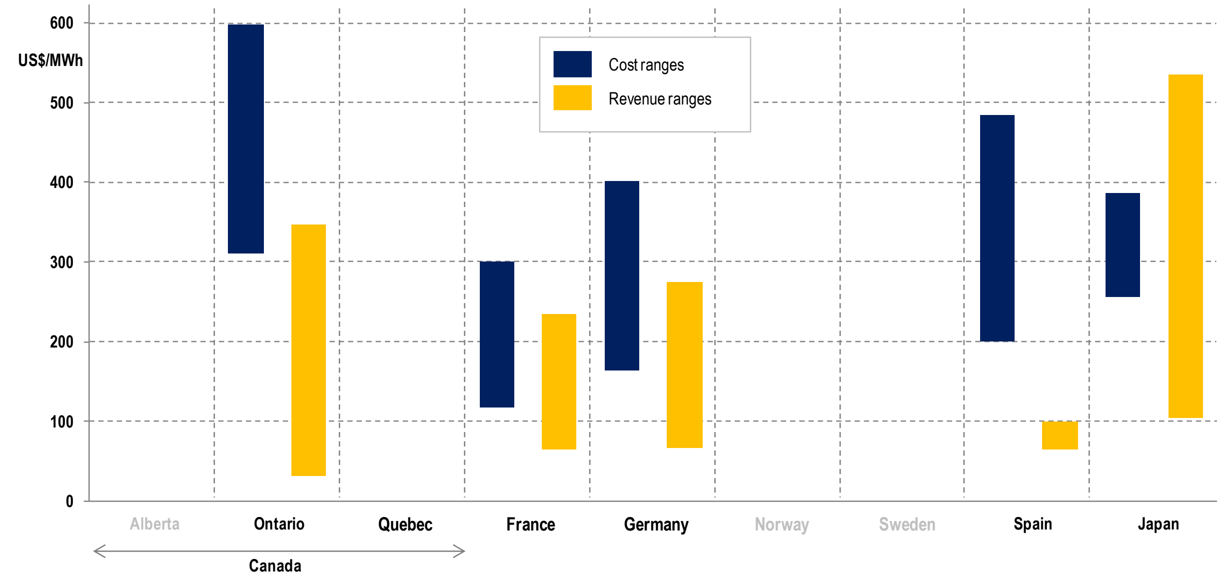


Figure 82. Solar PV – LCOEs and revenues of different countries (US$/MWh)[165]

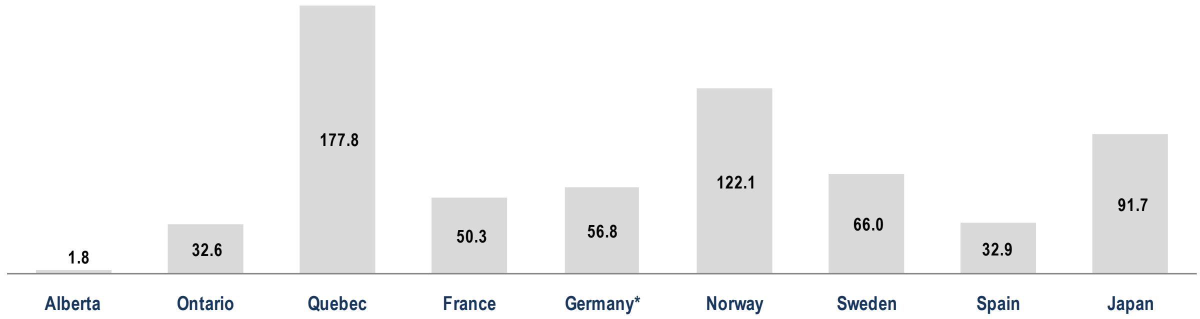
Regional differences in solar PV costs also reflect the quality of the resource, solar radiation. The costs of solar PV generation are highly dependent of the ranges of plant availability, and plant efficiency. The results obtained in simulations appear to confirm that plants in higher latitudes have also higher costs of generation. This assertion must be taken with care. As discussed above, the ranges of costs of solar PV depend on many factors. In fact, costs of the solar PV plants in Spain appear to be one of the highest. This is a counterintuitive result, considering the good quality of solar radiation in most of the country. A more detailed assessment of the specific plants included in the database concluded that the latest solar PV plants built in Spain may not have been located in the most attractive locations.

Breakthrough plants: Some plants operating in the regions in the scope of the study claim they are attaining at the present costs of generation up to 30% lower than those of average new solar PV plants. This assertion may actually reflect upcoming, steep costs reductions in this technology.

[165] Source: Prysma analysis. LCOE breakdown and business cases in Section 5.

5.4 Hydro – Cost of generation

The installed base of hydro generation in the countries in the scope of the study is shown in Figure 83. Hydro is a key generation technology in some of these regions/countries:



2.7%	21.6%	96%	9.3%	9.8%	95.2%	44.9%	11.4%	8.3%

France, Germany, Spain, Norway, Sweden and Japan: Data from year 2011 | **Alberta, Ontario and Quebec:** Data from year 2010

*consolidated Hydro and Biomass

Figure 83. Hydro generation (TWh) per country and percentage of total generation[166]

Canada: Hydro represented 57% of the installed capacity and 59% of the total electricity production in Canada in 2010. The significance of hydro is very variable across the provinces in the scope of this study: Not very relevant for Alberta, very significant for Ontario, where 22% of production in 2010 was based on hydro, and representing practically the totality of the production in Quebec (97% in 2011).

France: Hydro represented 9.2% of the electricity produced in 2011, and it is forecast that it will account for 11% of total production in 2020. 20% of the installed capacity in France is hydro (2011). This proportion is forecast to continue at roughly the same level until 2030. In the same span of time, other RET (wind and solar) are forecast to grow from circa 7% of total installed capacity, and 1% of total production in 2011, to 7% of total installed capacity in 2020, and 27% of total electricity production in 2030 (the numbers may vary according to the source used).

Germany: In 2011, 4% of Germany's electricity production was based on hydro. This proportion is forecast to continue at roughly the same level (4-5%) until 2020. In this year, other RET will account for 31% of the total electricity production of the country.

Norway/Sweden: Hydro is the most relevant technology in Norway, where approximately 93-95% (2011)[167] of the electricity generated is based on hydro. In Sweden, hydro represented 45% of 2011 production.

Spain: Hydro was responsible for approximately 35% of total RET generation in the country in 2011, and of 20% of total installed capacity.

Japan: About 8% of the electricity produced, and 17% of the installed capacity in Japan was based on hydro in 2011. There is some uncertainty about the actual values, because different reliable sources for Japan quote slightly different figures depending on the year when they have been computed.

[166] Source: Data extracted from the summary in Figure 98.

[167] Source: Norway: NVE "Annual Report 2011 – The Norwegian Energy regulator". Data for 2012 ≈97%

Figure 84 shows a comparison of LCOE for different countries, using the database of new plants and projects of RE-COST, complemented with insights from public reports.

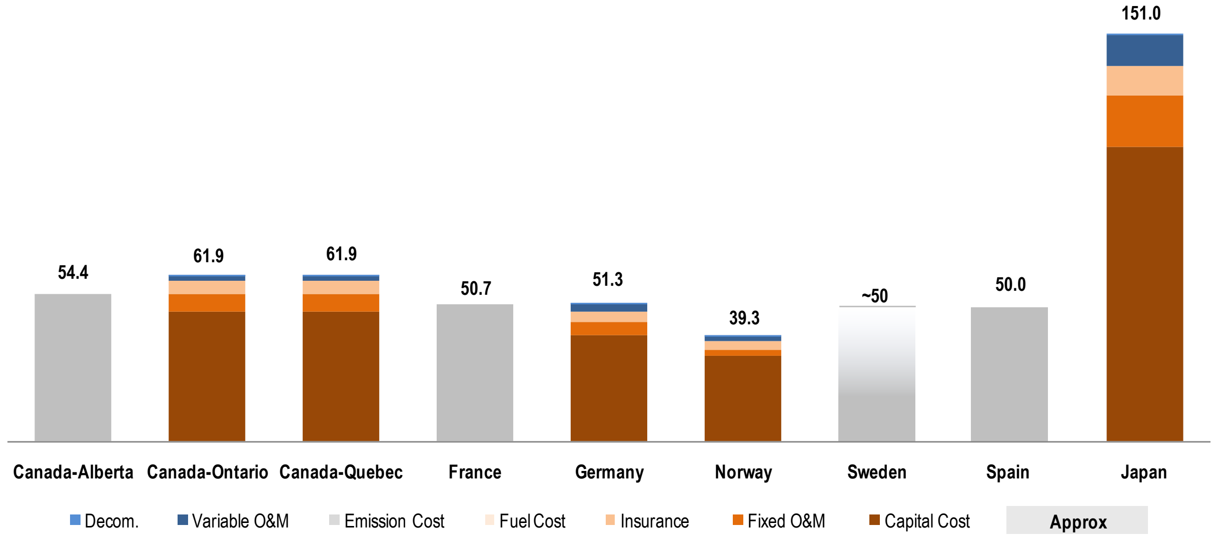


Figure 84. LCOE hydro by country (US$/MWh)[168]

Given the large differences between hydro plants (technologies, sizes, locations, systems, etc.), attain a level of accuracy in the cost analyses similar to that of other technologies would require to a larger set of generation plants and projects than that is included in the RE-COST database. Therefore, the analysis of hydro generation has been based on analyses of publications, complemented with interviews with experts, and with a relatively reduced number of real plants and projects. This has resulted in analyses accurate enough to use hydro as a comparison basis with other technologies, but not to extract in-depth implications from real generation plants and projects.

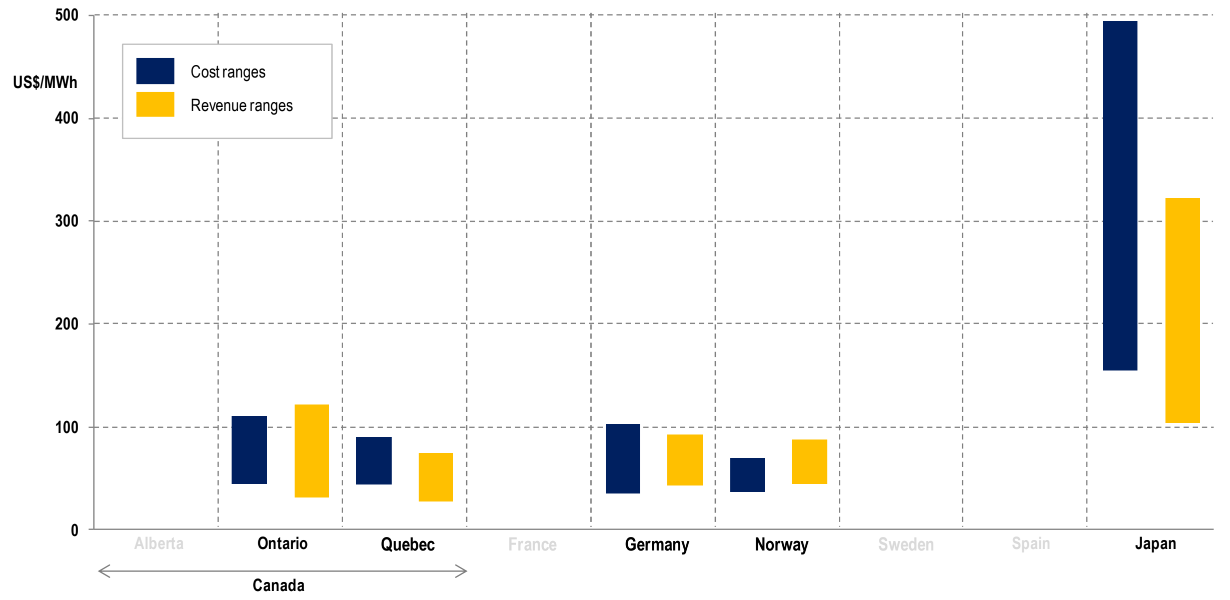


Figure 85. Hydro – LCOEs and revenues of different countries (US$/MWh)[169]

[168] Source: Prysma Analysis. Model data from an example plant (Size 50 MW, capacity factor 45% and discount rate 5%). Alberta, France, Sweden and Spain only for comparison purposes. Business case have not been calculated.

[169] Source: Prysma analysis. LCOE breakdown and business cases in Section 5.

Figure 85 shows a range of costs (LCOE) and revenues of hydro in the regions in the scope of the analysis, obtained from simulations of the RE-COST database of hydro projects, complemented with publications. Ranges of costs are similar in all countries with the exception of Japan, where LCOE ranges are wider and higher, mainly due to higher capital cost.

5.5 CCGT – Cost of generation

CCGT is one of the most extended technologies for power generation in the world. Figure 86 shows the total production, and the percentage of generation in the power mix of each of the countries and provinces included in this assessment[170].

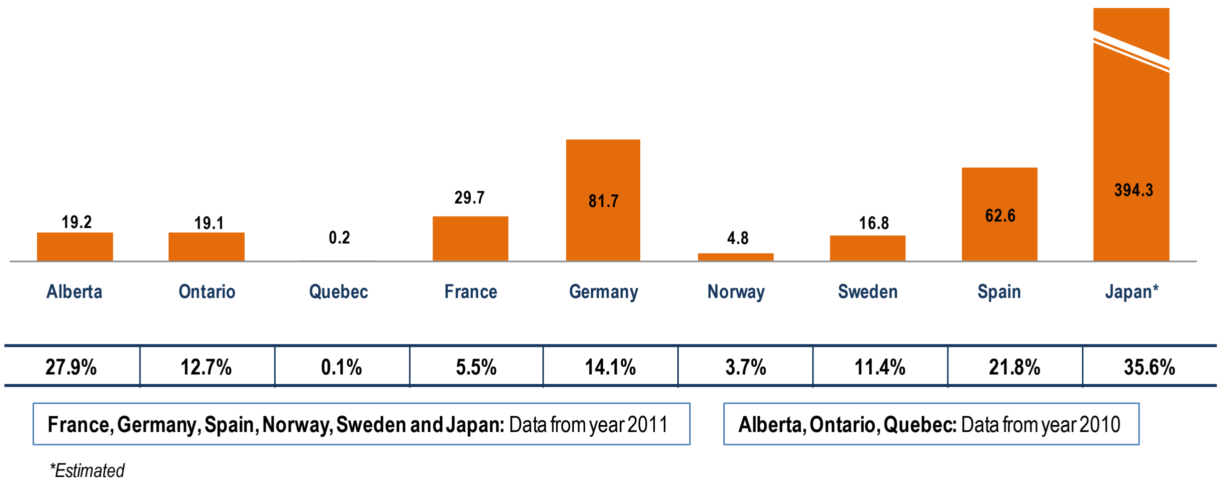


Figure 86. Gas-fired generation (TWh) per country and percentage of total generation[171]

CCGT (Combined Cycle Generation Plants) are thermal plants. They burn fuel to produce electricity. CCGT plants use two different types of turbines: gas and steam turbines. The number of gas turbines can vary from 1 to 4. In addition, CCGT plants may display diverse turbine configurations: same axis, two axes, etc. This provides a lot of flexibility to plant developers, who can choose the design and size most appropriate for their needs, and who can build CCGT plants in stages, augmenting installed capacity through the addition of another gas turbine. The drawback for this study is that it is necessary to be careful when comparing the results from gas-fired plants which use slightly different technologies.

Figure 87 shows a comparison of the LCOEs of gas-fired generation plants for the countries in the scope of RE-COST. A number of factors influence the cost of generation of this technology:

1. The costs of CCGT plants are heavily dependent on gas prices. Costs of gas-fired generation in Alberta are lower than the costs of similar plants in other regions due to the very low gas prices in the province. 4.14 US$/MMBtu was used as reference price of gas in Alberta, while the reference price of gas used in other Ontario was in a range (4-7.24[172] US$/MMBtu). As can be seen in Figure 87, when assessing gas-fired plants it is very important to have

[170] Data for Japan are estimated

[171] Data extracted from the summary in Figure 98. Japan Gas-fired generation has been estimated based on previous year (2010) percentage of this technology in thermal generation

[172] The source for the upper range of cost of gas in Ontario is Statistics of Canada Energy Statistics Handbook. But other sources depict significantly lower prices of gas for this province (4 US$/MMBtu – Ministry of Energy – Ontario) Therefore a range of costs, including the upper and lower limits, has been used to simulate the potential behavior of CCGT in the province.

accurate data about the characteristics and prices of the fuel used. Small differences may result in large variations in the costs of gas-fired generation. As a consequence, policies affecting the prices of gas used in generation have a large impact on the ultimate costs of this technology.

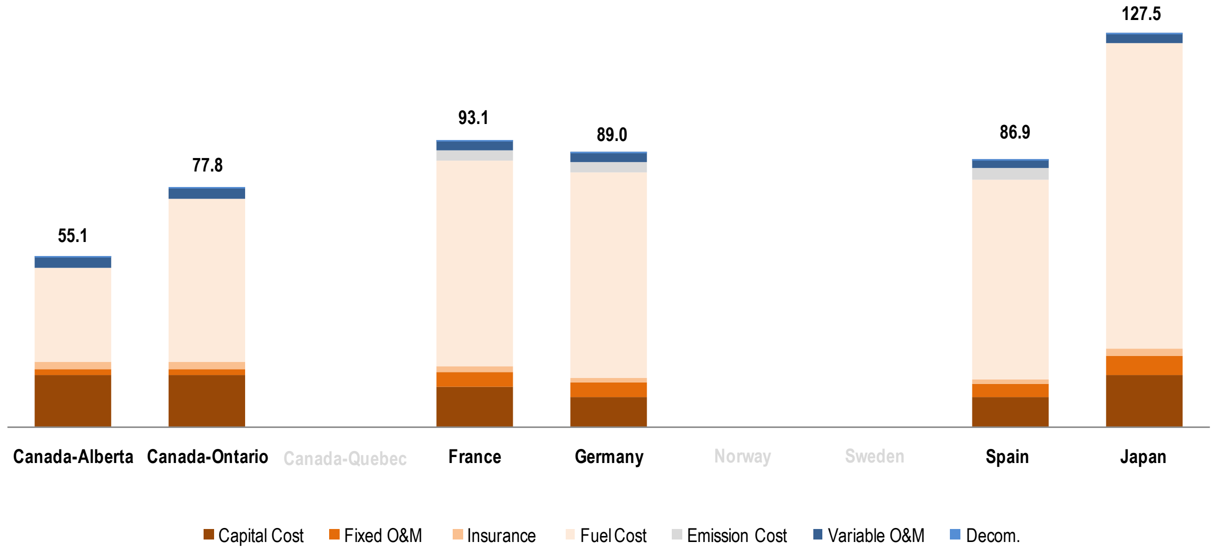


Figure 87. LCOE CCGT by country (US$/MWh)[173]

2. Gas-fired generation has traditionally presented very attractive costs. A number of factors contribute to this:

- Low capital costs (capital costs reported in interviews were 550-1,550 US$/MW) contribute to lower costs of generation.
- The average thermal efficiency of CCGT plants is rather high – 50-60%. This means that heat is very efficiently transformed into electricity, and contributes to reduce the factors costs of CCGT generation.
- However, O&M costs are higher than those of coal plants. New CCGT plants include high levels of automation. More delicate equipment may require more specialized maintenance crews.

3. Current low capacity factors damage the business case of gas-fired generation. In countries with priority feed-in for RET, CCGT enters at a later stage in the merit-order curve; after wind, solar, run-of-the-river hydro, and nuclear, as depicted in Figure 88. As a consequence, in countries with large proportion of wind and solar PV generation, CCGT plants may be working now at much lower capacity factors than were expected when they were built. Some of them were designed to operate as base load plants, but may be now operating at peak load. This situation significantly damages the business case of generation for this technology through at least two mechanisms:

- The cost of generation per MWh increases. Plant costs must be allocated to a smaller amount of electricity produced.
- Starting and stopping the plant more frequently than expected in its design specifications creates thermal fatigue in a number of components. This, in turn, increases maintenance costs.

Unit generation costs from underutilized CCGT plants can increase as much as 25-40%. Utilities in Germany and Spain are starting to mothball some of their thermal plants, and are giving up projects to acquire existing plants[174]. New investments in CCGT plants have in some cases to be justified at 10-20% capacity factors (900 hr/yr)[175].

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[173] Source: Prysma Analysis. Model data from an example plant. (Size 400 MW, capacity factor 75% and discount rate 5%).

[174] Data from sector news.

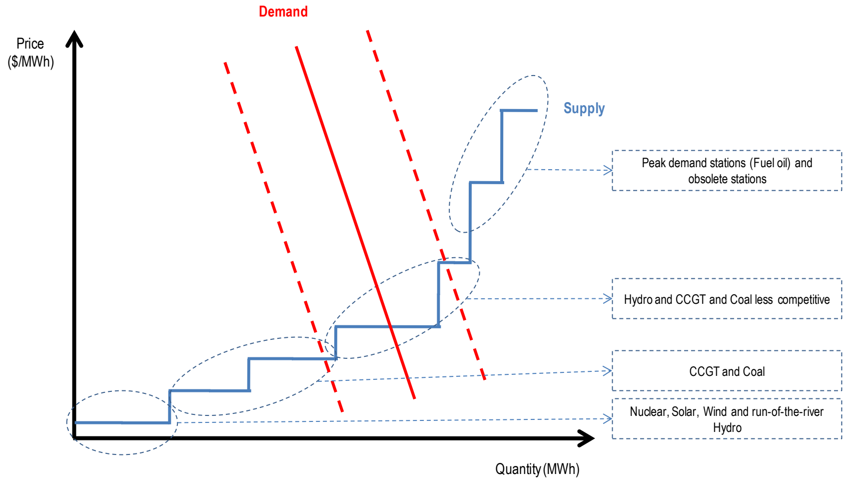

Figure 88. Example of Merit-order-curve – Spain [176]

Interviews with utilities have highlighted the large impact that low capacity factors of gas-fired and other non-RET plants are having on their P&Ls. Utilities with a diverse mix of generation may hedge against this impact: They claim they do not reap almost any benefits from their thermal plants (CCGT and coal), but they compensate with the results from their renewable plants. The real problem is for utilities with a large proportion of traditional generation, that have many plants being used at peak capacity or balancing capacity for intermittent plants, not as base load plants.

4. Emissions: CCGT is a cleaner technology than coal, with lower level of emissions per BTU. But still produces 450 kg/CO_2 per MWh, that at a price of around 10 US$/t of CO_2 could add 4.5 US$/MWh to the generation costs of gas. Figure 89 shows a comparison of LCOE and revenues for gas-fired generation for different countries, using the database of new plants and projects of RE-COST, complemented with insights from public reports.

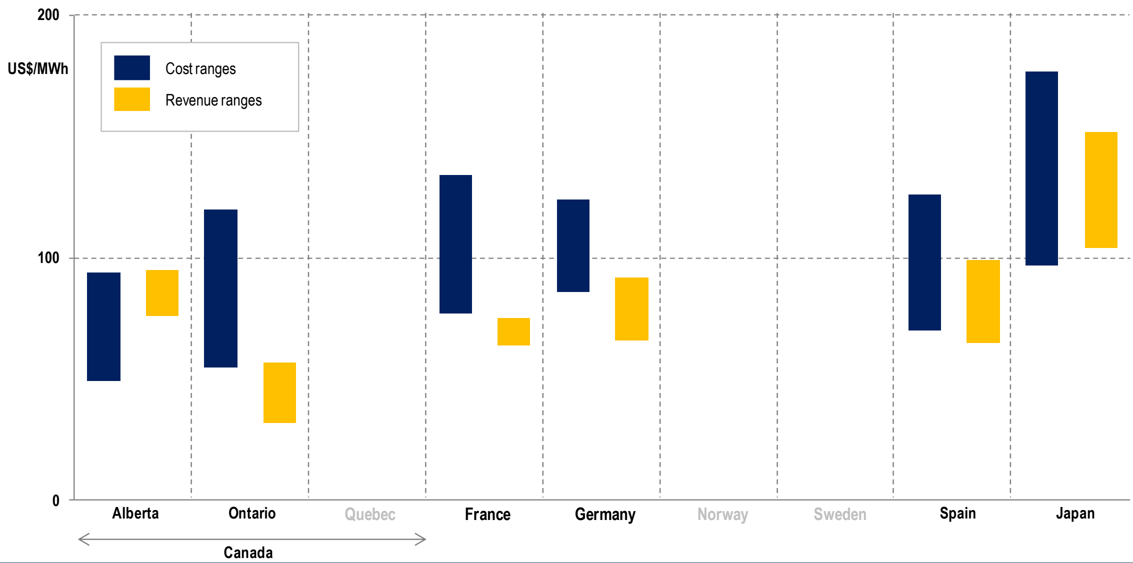

Figure 89. CCGT – LCOEs and revenues of different countries (US$/MWh) [177]

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[175] It would be different for each country. For instance, in Ontarians gas-fired plants, the capacity factor is closer to 40% than 20% and in the future CCGT plants will increase their utilization as coal-fired plants comes offline and nuclear units undergo refurbishment.

[176] Source: Energía y Sociedad – Merit order curve for Spain. This is meant as an example only. The merit order curves in other regions in scope of RE-COST may be very different

5.6 Coal – Cost of generation

Figure 90 shows the coal-based production and proportion of generation in the countries and provinces in scope of this study.

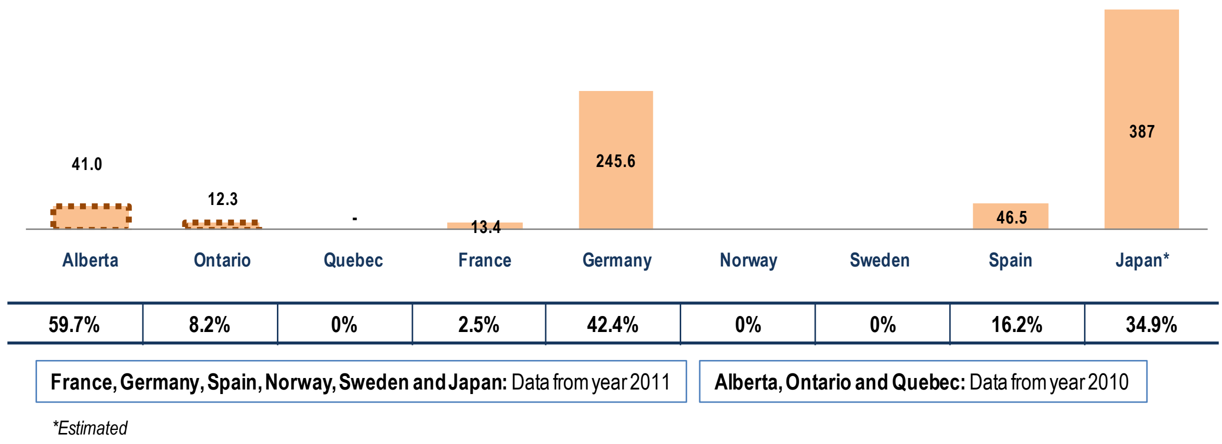

Figure 90. Coal-fired generation (TWh) per country and percentage of total generation[178]

Coal-fired plants are widely used worldwide as reliable, cost-effective generation sources. Coal-fired plants transform the energy released by burning coal into electricity. Heat produces steam, which moves a steam turbine, which turns a power generator. The efficiency of the process, as well as the emissions produced, depend very much on two factors (1) the specific systems of the plant – with large variations depending on the specific technologies and components used, and (2) the type of coal that is burned, and the impurities it contains.

The focus of this study is pulverized coal-fired generation, a technology that started to be used 10 years ago. By feeding pulverized coal to enhanced combustion burners it is possible to increase the temperature of the combustion cycle, and to increase the thermal efficiency of the plant. This not only reduces the unit cost of generation, it also reduces the proportion of emissions (CO_2, NO_x and particles), and therefore the potential costs of emissions. The downside is that the higher temperatures reached require more advanced, and therefore more expensive materials. Capital costs of pulverized coal-fired plants are higher than those of traditional coal-fired plants.

Figure 91 shows a comparison of LCOE for different countries. Several factors account for the results:

[177] Source: Prysma analysis. LCOE breakdown and business cases in Section 5.

[178] Data extracted from the summary in Figure 98. Japan coal-fired generation has been estimated based on previous year (2010) percentage of this technology in thermal generation.

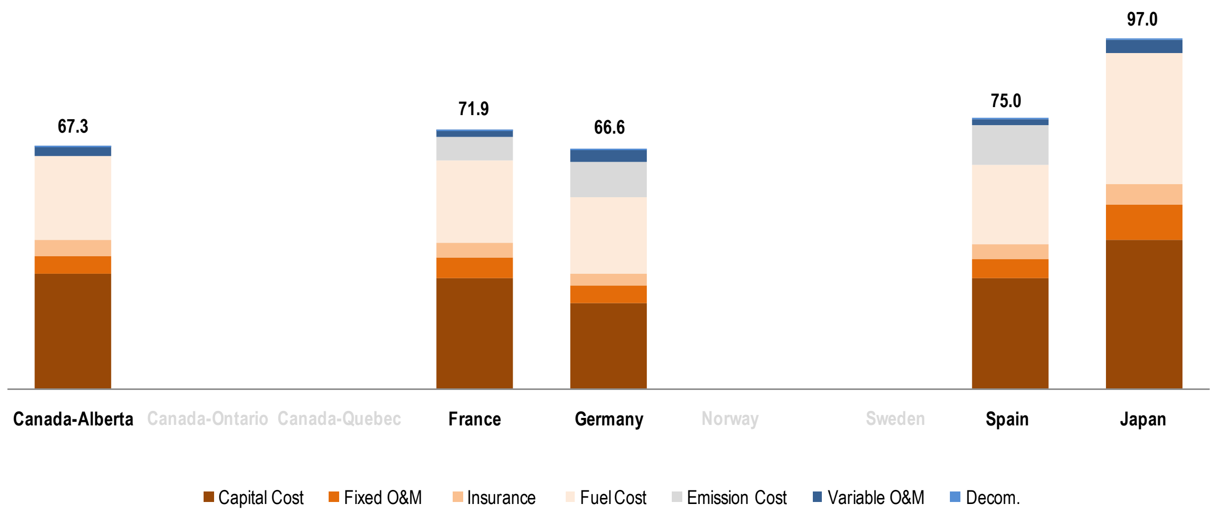

Figure 91. LCOE coal by country (US$/MWh)[179]

1. Costs of coal-fired plants are heavily dependent on coal prices. Coal represents ~30-40% of the total cost of generation of a coal-fired plant. This proportion, although lower than the proportion that the cost of gas represents in the cost of gas-fired generation, is high enough to significantly influence the business case of a plant. When assessing coal-fired plants it is very important to have specific data about the characteristics and prices of the coal actually used. Relatively small differences in the thermal characteristics of coal may result in large differences in generation costs.

2. Coal-fired plants display very attractive O&M costs: New coal-fired plants have higher levels of automation than older plants. This results in lower operation costs. Also, in general, coal-fired plants have lower unit maintenance costs than those of CCGT plants. Labor costs are lower because of two factors (1) economies of scale in maintenance crews, and (2) lower level of specialization required. Coal plants are sturdier, and are easier to repair and maintain than CCGT plants[180].

3. Flexibility and dispatchability: Coal-fired plants are dispatchable. They can be started and stopped easily. In addition, they can be operated at 50% of design output without losing as much efficiency as gas-fired plants.

4. Impact of emissions: Coal is the dirtiest technology. CO_2 equivalent emissions from a typical coal plant are ~0.97 t/MWh. If emissions are priced at 10 US$/ton (2010-2011 levels), additional 9.7 US$/MWh are added to the costs of generation of the average coal generation plant. A number of emission reduction technologies are being explored, for instance, CCS (Carbon Capture Storage). But they are not yet very cost effective, and have not been included in the scope of RE-COST.

5. Low capacity factors: Coal is suffering from the same issues of low overall plant capacity as CCGT (see Section 5.6). The average capacity factors of coal plants now are smaller than several years ago. Therefore, generation costs have increased as much as 50-70%. This has result in some coal-fired plants being mothballed[181].

Figure 92 shows ranges of costs and revenues of coal generation in the regions in the scope of the analysis.

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[179] Source: Prysma Analysis. Model data from an example plant. (Size 400 MW, capacity factor 60% and discount rate 5%).

[180] Source: Data from interviews with utilities.

[181] E.ON Francestopped `pwer generation from existing coal fired units in 2021. Source. Sector publications.

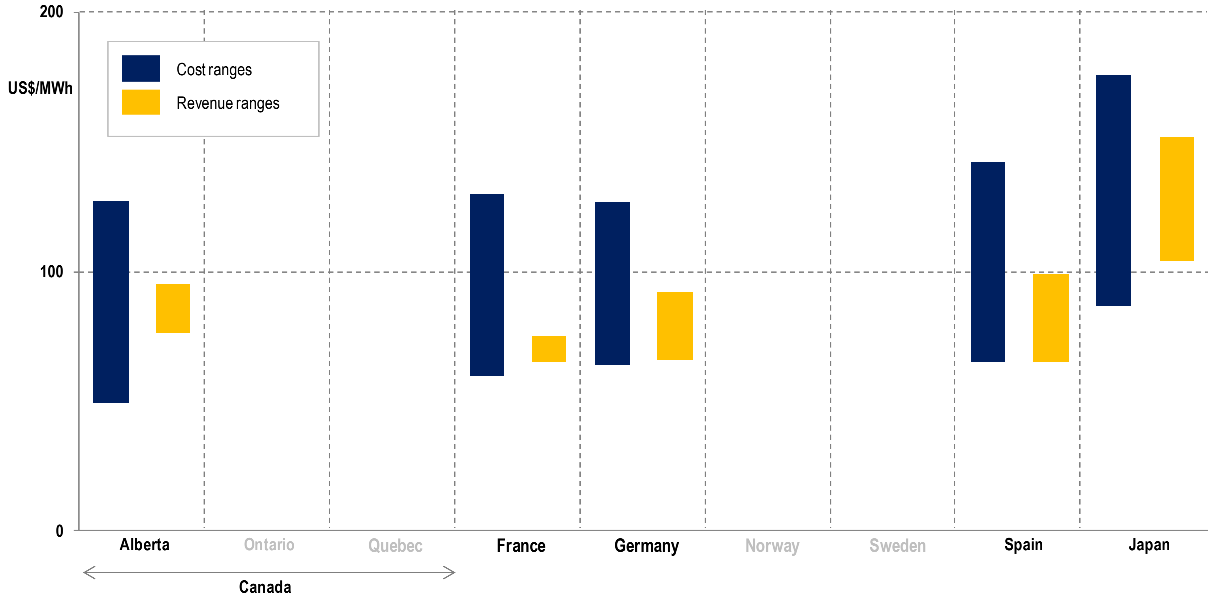

Figure 92. Coal – LCOEs and revenues of different countries and revenues (US$/MWh)[182]

[182] Source: Prysma analysis. LCOE breakdown and business cases in Section 5.

6. THE BUSINESS CASE OF GENERATION BY COUNTRY/TECHNOLOGY – INSIGHTS

As stated in the previous sections, the market situation, and the incentives to generation may have as much or more impact in the business case of a given region/technology pair than the situation and evolution of different generation technologies. An understanding of the context of electricity generation and its evolution is critical to understand the results of the simulations conducted in the framework of RE-COST.

The map below depicts the countries included in the analysis (primary countries), and the countries that although are not included in the scope of the study, may be influenced by developments taking place in the primary countries.

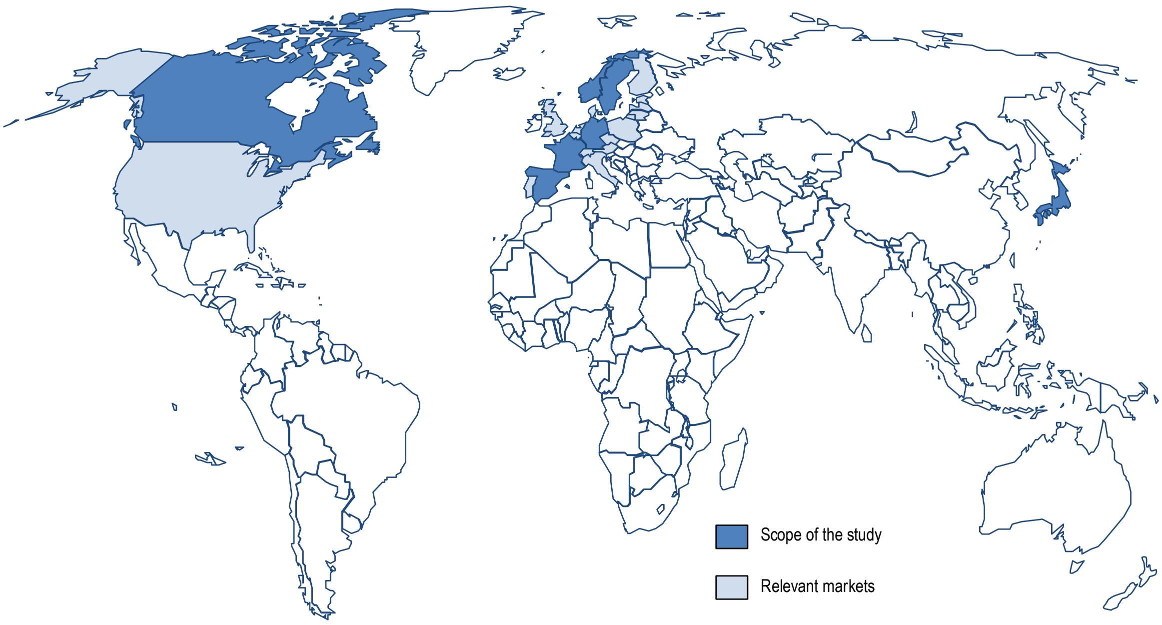

Figure 93. Countries and regions in the scope of the analysis

6.1 Countries and regions in the scope of the analysis

Canada is a federal state, divided in 10 provinces and 3 territories. The regulation of the electricity market, and a significant part of the electricity sector responsibilities are under provincial jurisdiction. Under federal responsibility is the management of the interprovincial and international trades of energy (National Energy Board); the regulation of Canada´s nuclear industry (Canadian Nuclear Safety Commission); and other aspects that are defined as of national interest[183]. Canadian provinces and territories have different market and regulatory models[184]:

- **Reformed provinces:** Alberta has a deregulated power market, and Ontario has a hybrid power market. Both have created independent operators. Wholesale electricity prices are not regulated. However, in Ontario, most of the market participants have contracted rates with the Ontarian Administration.
- **Hydro provinces:** British Columbia, Quebec, Manitoba, Newfoundland and Labrador. Their generation mix is mainly based on hydro power. Their power sectors are not significantly reformed, maintaining considerable

[183] Transmission is regulated in most of the provinces and rates are usually set by the corresponding provincial authority.

[184] Source: ICEX – Guide to investors in the power sector in Canada 2012

levels of vertical integration. Provincially owned utilities are the main actors in the electricity sector. Electricity prices are regulated.

- **Vertically integrated provinces:** New Brunswick, Saskatchewan, Nova Scotia and Prince Edward Island have vertically integrated electricity production systems. Power generation is mostly based on coal-fired plants.
- **The Territories** are very small markets and are located far away from the other provinces. Include the Northwest Territories, Nunavut and Yukon. Together they represent ~0.2% of the electricity generation of Canada (2011).

The assessment of Canada focuses on the evaluation of the three largest electricity markets within this country: Alberta, Ontario and Quebec. These provinces account for 70% of Canadian power production[185]. In addition, they display very diverse market models, and have established different policy approaches to support generation. This contributes to increasing the relevance of analyses and comparisons.

Norway and Sweden – The Nordic electricity market encompasses Denmark, Finland, Norway and Sweden. These four countries – with diverse generation models – have defined an integrated electricity market, and are active partners in electricity trading. Norway and Sweden, the largest contributors to the Nordic Market with 73% of its total generation (2011), established in 2012 a joint green certificate market with a shared ambition level.

Germany exerts a considerable influence in the European electricity sector, not only because of the sheer size of the German electricity market, but also due to the country strong support of RET. This support has contributed to position Germany as the first country in Europe, and the fifth in the world, in terms of renewable installed capacity[186].

France has a distinctive power mix, with a large proportion of nuclear generation. Nuclear power has allowed France to maintain relative low domestic prices of electricity, and to be a net power exporter to neighboring countries. The high reliance in nuclear power has also contributed to reduce GHG (greenhouse gas) emissions. The role of nuclear power in the French generation portfolio, how it should evolve in the future, and the implications for the development of other energy sources are important elements to understand the future of generation in Europe.

Spain – In the last two decades Spain has maintained a vigorous support of renewable technologies through a variety of policy instruments and incentives. This has resulted in very high levels of renewable installed capacity (44.4% in 2011[187]). The reliance in renewable sources is critical for a country with very few domestic energy sources. Currently the discussion in Spain focuses on how to optimize the development of the electricity sector, while reducing the costs associated to incentives and support to RET, and non-RET generation.

Japan – A large basis of nuclear generation (25% in 2010)[188] has contributed to reduce the country high dependence on fossil fuel imports. In the aftermath of the Fukushima incident, Japan has to determine the role that nuclear power will have in the future generation mix of the country (9% of electricity was generated by nuclear plants in 2011). Policy makers are contending with widespread mistrust about nuclear generation, and the

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[185] In 2010, generating capacity in Canada amounted to approximately 130 GW. A large proportion of this figure consisted of renewable sources (62%). Hydro represented 57% of total capacity. Nuclear generation was responsible for almost 10%. The remaining 28% consisted of thermal plants, mainly coal and gas-fired. Electricity production in 2010 was 588.9 TWh. 63% came from renewable sources, 14% from nuclear and 23% from fossil generation – SOURCE: Statistics Canada, 2010 catalogue 57-202 Electricity Generation, Transmission and Distribution

[186] Source: ENERGICI – Germany Renewable Energy Profile

[187] Source: El Sistema Eléctrico Español. Informe 2011 (REE)

[188] Source: Japan 2010: Japan electric power information center. "Operational and financial data". Japan 2011: ANRE Power Survey Statistics Catalogue 2012 (fiscal 2011)

strong desire of the Japanese people to transition out of nuclear, while maintaining affordable electricity prices, and reducing the country's dependence on imported fuels. In addition, supporting the development of RET is an item high in the agenda of many policy makers in the Japanese electricity sector.

The next pages summarize some of the most salient characteristics of the regions and countries in the scope of RE-COST. Unless otherwise stated, 2011 has been used as base year to characterize the electricity sectors of the countries in scope. Exceptions include Canada. Canadian data are based on 2010 results, because complete and consistent 2011 data were not available at the time of completing the report. In the case of Japan, most of the data shown are from fiscal year 2011, the last year with stable generation information.

Baseline data have been complemented with information from 2012, to assess the rapid changes taking place in the country's generation portfolio and their implications.

	Canada - Alberta	Canada - Ontario	Canada - Quebec	France	Germany	Norway	Sweden	Spain	Japan
Market	Liberalized market	Hybrid: regulated-competitive	Government owned integrated utility	Deregulated market. Concentrated	Deregulated market. 4 main vertically integrated players very relevant along the supply chain.	Liberalized market but with large state owned utility	Liberalized market but with large state owned utility	Deregulated market. 3 large, integrated utilities very relevant along the supply chain.	Deregulated. 10 Electric Power Companies (EPCOs) as regional actors.
Main Utilities	• Capital Power • TransAlta, • ENMAX, • TransCanada	• Ontario Power Generation • Bruce Power	• Hydro-Quebec Production	• EdF • GDF Suez • E.ON France • Vattenfall • Enel	• Vattenfall, • E.ON • EnBW • RWE	• Statkraft • E-CO Energi • Norsk Hydro	• Vattenfall • Fortum Sverige • E.ON	• Endesa • Iberdrola • Gas Natural Fenosa	• 10 EPCOs • Other: PPSs, SEUs
Regulator	Alberta Utilities Commission	Ontario Energy Board	Régie de l'énergie	Commission de régulation de l'énergie	Bundesnetzagentur	The Ministry of Petroleum and Energy	Energy Markets Inspectorate	Comisión Nacional de Energía	Ministry of Economy, Trade and Industry
Grid owner/Operator	• AltaLink • Others	• Hydro One • Others	• Hydro-Quebec TransÉnergie	• Réseau de transport d'électricité	• Amprion GmbH • EnBW Transportnetze AG • TenneT TSO GmbH • 50Hertz Transmission GmbH	• Statnett SF • Others	• Svenska Kraftnät	• Red Eléctrica Española (REE)	• EPCOs • Others

Figure 94. Summary – Country characteristics

	Canada (2010)	Alberta (2010)	Ontario (2010)	Quebec (2010)	France (2011)	Germany (2011)	Norway (2011)	Sweden (2011)	Spain (2011)	Japan (2011)
Total Demand (TWh)	**513.7**	**51.6**	**130.2**	**181.3**	**443.3**	**538.5**	**113.0**	**146.8**	**239.9**	**931.0**
Prime generation Sources	Hydro	Thermal	Nuclear	Hydro	Nuclear	Coal	Hydro	Hydro	Thermal	Thermal
Installed Capacity (GW)	**130.7**	**12.8**	**35.6**	**42.1**	**126.4**	**167.8**	**31.7**	**36.5**	**105.9**	**285.7**
Nuclear	10.4%		33.7%	1.6%	49.9%	7.0%		25.7%	7.3%	17.1%
Gas[189]	28.2%	85.7%	37.5%	4.8%	7.5%	15.0%	3.4%	21.9%	29.7%	64.9%
Coal					6.3%	28.0%			11.5%	
Other non-renewable	n.r.	n.r.	n.r.	n.r.	8.2%	11.0%	n.r.	n.r.	7.0%	n.r.
Hydro[190]	57.0%	6.9%	23.7%	91.3%	20.1%	7.0%	95.0%	44.4%	18.5%	16.9%
Wind	3.0%	6.3%	4.1%	1.6%	5.2%	17.0%	1.6%	8%	20.1%	0.8%
Solar PV	0.1%	n.r.	0.3%	n.r.	1.7%	15.0%	n.r.	n.r.	4.0%	~0%
Other renewable	1.3%	1.1%	0.8%	0.7%	1.0%	n.r.	n.r.	n.r.	1.8%	0.2%
Projected renewable (MW)[191]		4,053	7,587	7,307	35,700	44,332	*	*	19,117	*
Total Supply (TWh)	**588.9**	**68.7**	**150.6**	**185.2**	**541.9**	**579.3**	**128.1**	**146.9**	**287.2**	**1,107.8**
Nuclear	14.5%		54.4%	1.9%	77.7%	17.6%		39.5%	20.1%	9.2%
Gas	8.6%	27.9%	12.7%	0.1%	5.5%	14.1%	3.7%	11.4%	21.8%	35.6%[192]
Coal	12.6%	59.7%	8.2%	0.0%	2.5%	42.4%			16.2%	34.9%[193]
Other non-renewable	2.2%	4.1%	0.2%	0.3%	1.5%	5.2%	n.r.	n.r.	11.2%	11.4%[194]
Hydro[195]	59.1%	2.7%	21.6%	96.0%	9.3%	9.8%	95.2%	44.9%	11.4%	8.3%
Wind	1.6%	3.1%	2.0%	1.0%	2.2%	7.9%	1.0%	4.2%	14.7%	0.4%
Solar PV	0.0%	0.0%	0.1%	0.0%	0.3%	3.0%	n.r.	n.r.	2.6%	~0%
Other renewable	1.4%	2.5%	0.7%	0.6%	1.0%	n.r.	n.r.	n.r.	2.0%	0.2%

Figure 95. Summary – Country / province baseline of power generation.

No generation exists

[189] Official sources do not provide an accurate breakdown of thermal generation (Norway, Sweden and Japan). IEA Data (2009) Production. Norway: 3.5% thermal consist of 0.1% coal and peat, 3.2% gas, 0.0% oil, 0.1% biofuels and 0.1% waste. Sweden: 11.8% thermal consist of 1.2% coal and peat, 1.1% gas, 0.5% oil, 7.6% biofuels and 1.3% waste. Japan: 62.6% thermal consist of 26.7% coal and peat, 27.2% gas and 8.7% oil

[190] n.r.: not relevant

[191] Ontario, Alberta and Québec are projections until 2016. France, Germany and Spain include projections until 2020. *Norway and Sweden have a joint renewable target of reaching 26.4 TWh of electricity production in 2020 through the green certificate market. Japan plans to increase renewable energy generation to 300 TWh by 2030

[192] Prysma analysis

[193] Prysma analysis

[194] Prysma analysis

[195] In Germany hydro and biomass are indicated together as hydro

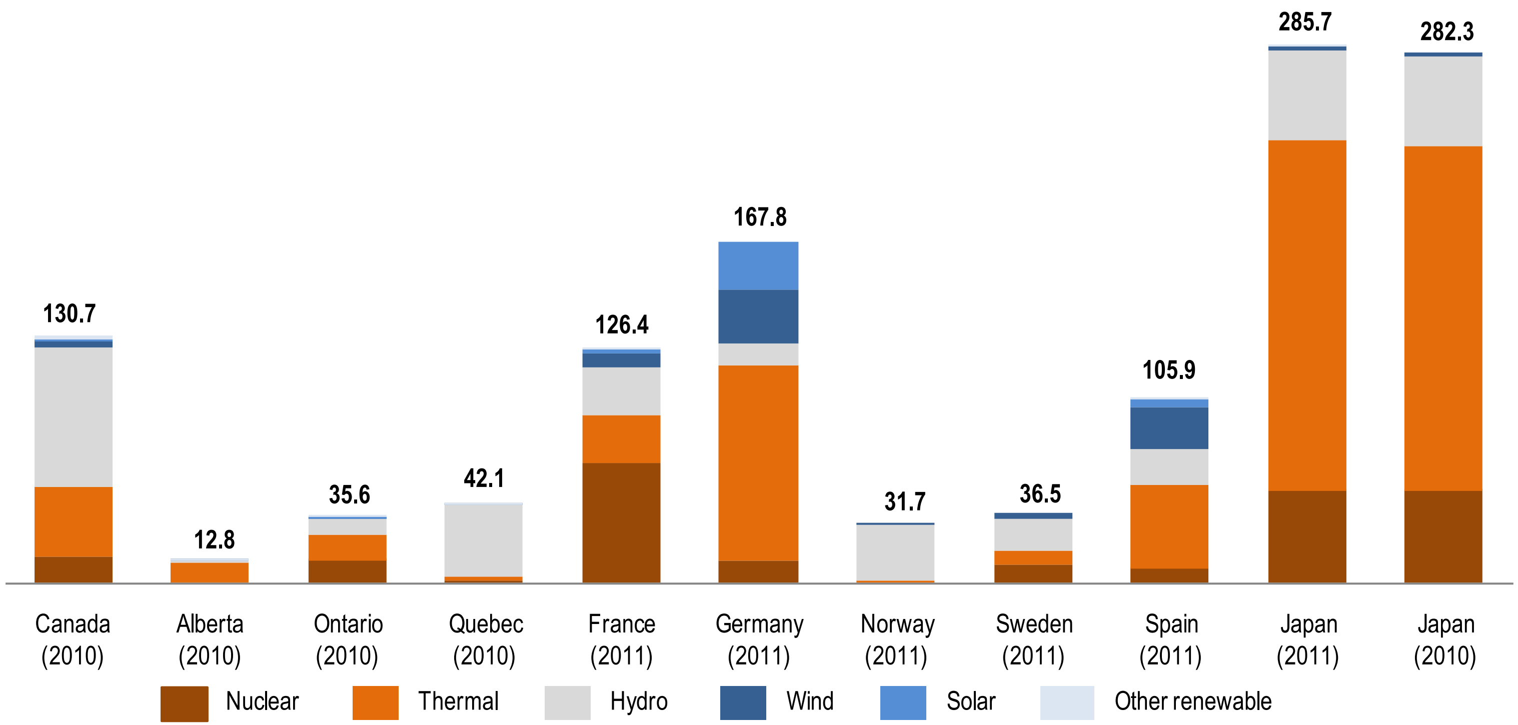


Figure 96. Summary – Installed power (GW) by country / province[196]

[196] Sources: Canada: Statistics of Canada, CANSIM: tables 127-0008 and 127-0009. France: Réseau de transport d'électricité, *"Bilan électrique 2011"*. Germany: World Energy Council „Energie für Deutschland 2012",. Spain: El Sistema Eléctrico Español. Informe 2011 (REE). Norway: NVE "Annual Report 2011 – The Norwegian Energy regulator". Sweden: Swedenergy "The Electricity Year Operations 2011", August 2011. Japan 2010: Japan electric power information center. "Operational and financial data". Japan 2011: ANRE Power Survey Statistics Catalogue 2012 (fiscal 2011)

Note: Official Swedish sources (Swedenergy) do not appear to have published the breakdown of thermal generation for 2011 (most recent and original data available). The last breakdown was done in 2009 by IEA (see footnote 6).

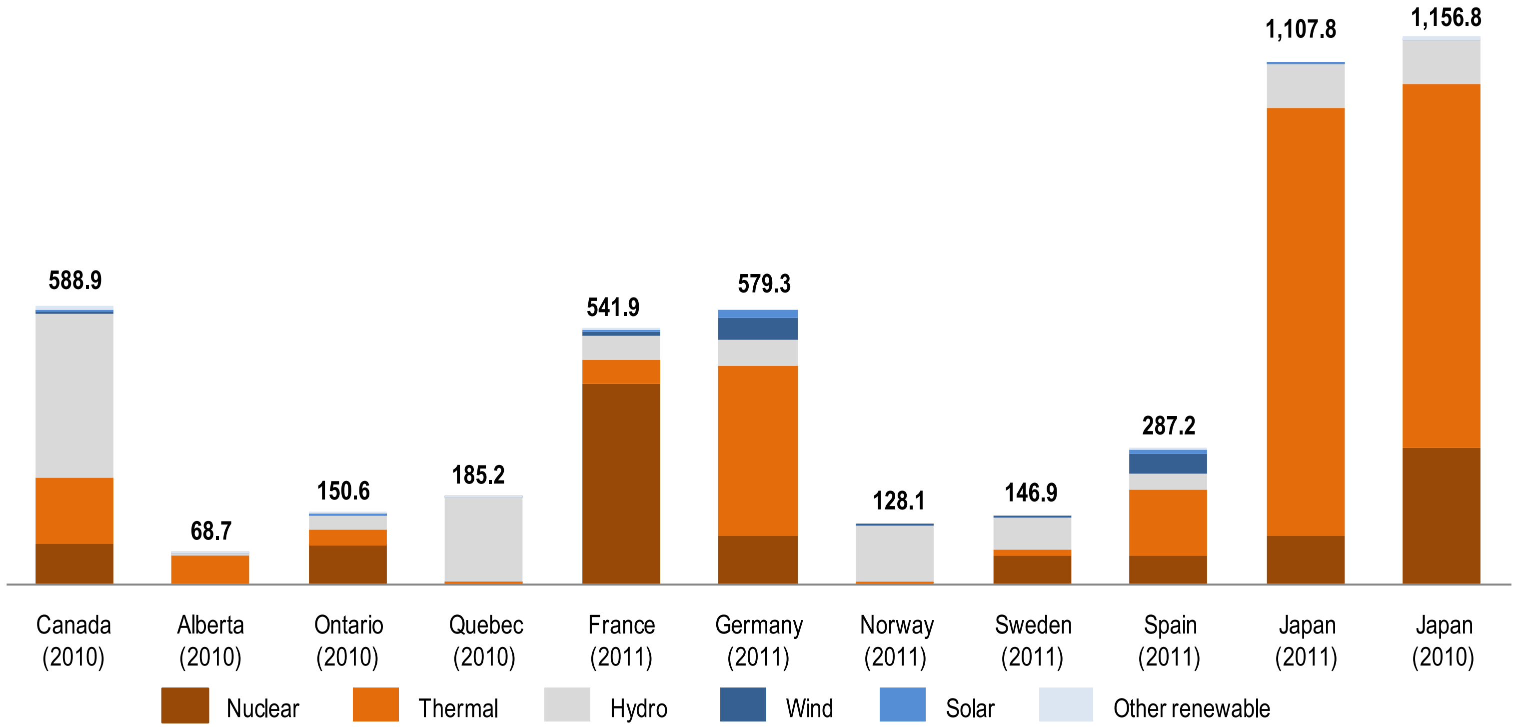


Figure 97. Summary – Domestic electricity generation (TWh) by country / province[197]

[197] Sources: Canada: Statistics of Canada, CANSIM: tables 127-0008 and 127-0009. France: Réseau de transport d'électricité, *"Bilan électrique 2011".* Germany: World Energy Council „Energie für Deutschland 2012",. Spain: El Sistema Eléctrico Español . Informe 2011 (REE) . Norway: NVE "Annual Report 2011 – The Norwegian Energy regulator". Sweden: Swedenergy "The Electricity Year Operations 2011", August 2011. Japan 2010: Japan electric power information center. "Operational and financial data". Japan 2011: ANRE Power Survey Statistics Catalogue 2012 (fiscal 2011)

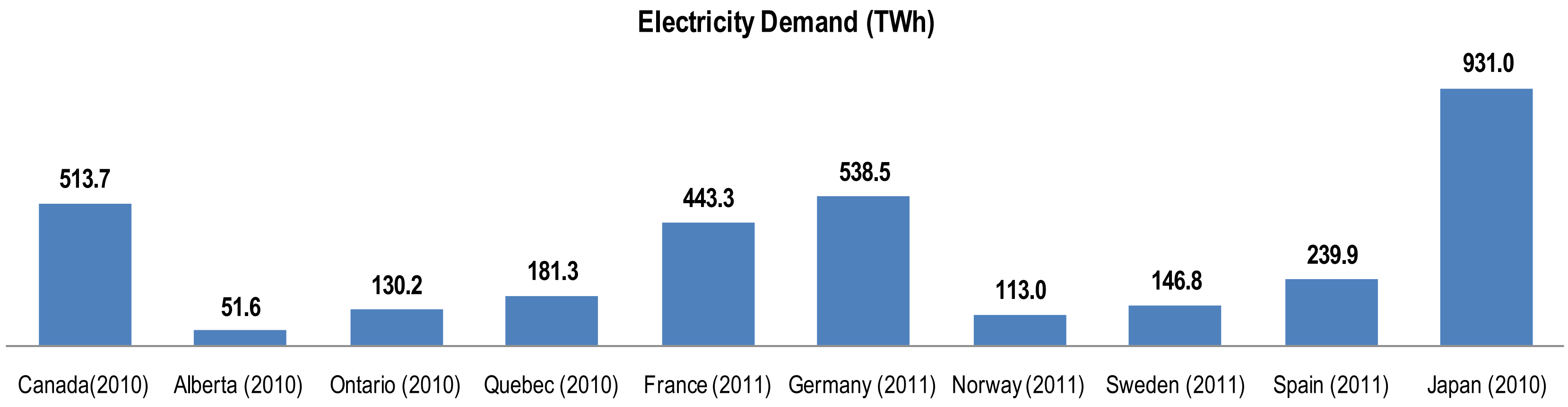


Figure 98. Summary – Electricity demand (TWh) – 2011[198]

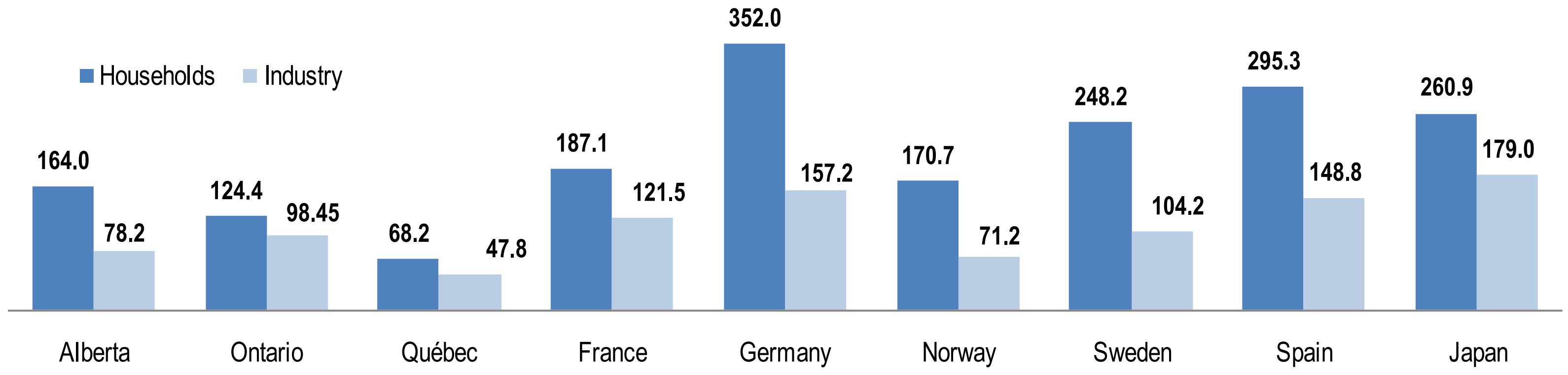


Figure 99. Summary – Retail prices[199] (US$/MWh) of electricity by country / province – 2011[200]

[198] Source: Canada: Statistics Canada. 2010 catalogue 57-202 Electricity *Generation, Transmission and Distribution.* Alberta : ERCB. France: Réseau de transport d'électricité. *"Statistiques Production Consommation Echanges 2011"* . Germany: World Energy Council "Energie für Deutschland 2012". Spain: El Sistema Eléctrico Español –Informe 2011 (RE). Norway: NVE „Annual Report 2011 – The Norwegian Energy regulator". Sweden: Swedenergy "The Electricity Year Operations 2011". Japan: Japan electric power information center: "Operational and financial data".

[199] The retail price refers to the price that end consumers pay for electricity.

Technology		Alberta	Ontario	Quebec	France	Germany	Norway	Sweden	Spain	Japan
Wind	**On-shore**	• Offsets/Carbon Credits ~9.75CA$/MWh • RECs • Scientific Research and Experimental Development Investment Tax Credits • Accelerated Capital Cost Allowance • Climate Change Emissions Management technology fund • Research and Technology Program	• Refundable Tax Credit for qualifying R&D • Northern Energy Program • FIT (20y): 0.115 CA$/kWh • Accelerated Capital Cost Allowance		• Tax Credit for R&D • FIT(base year 2007): 10y = 8.2€¢/KWh; <11-15y = 2-8.2 €¢/KWh	• R&D grants • KfW credits • FIT (20y): 4.87-8.93 €¢/kWh • Repowering Bonus: 0.5 €¢/kWh • System service Bonus: 0.48 €¢/kWh • Market Premium I	• Tax allowance for R&D costs • ENOVA support programs • Green Certificates 15 years • RENERGIX • Innovation Norway	• Green certificates • Subsidy: R&D grants • Tax reduction for real estate • Measures to support wind farms in difficult locations • Linear depreciation	• No support scheme available for plants coming into operation after Jan 2013 • *FIT: <20y = 8.1270€¢/kWh; >20y = 6.7921€¢/kWh* • *Premium Tariff first 20 years*	• 100% depreciation deduction 1st year • Tax base reduction for depreciable assets • FIT (20y): 23.1¥/kWh
	Off-shore			• Tax Credit for R&D • Green technology Demonstration Program • PAIE • Call for tender • Accelerated Capital Cost Allowance	• Tax Credit for R&D • Call for tender or FIT(base year 2007): 10y = 13€¢/KWh; <11-20y = 3-13 €¢/KWh	• R&D grants • KfW credit • FIT (20y): 3.5-19 €¢/kWh • Market premium I		• Green certificates • Subsidy: R&D grants • Energy tax reduction for non-commercial producer/supplier) • Measures to support wind farms in difficult locations • Linear depreciation		
Solar PV			• Refundable Tax Credit for qualifying R&D • Northern Energy Program • FIT (20y): <10kW 0.445CA$/kWh; 10<500kW 0.388CA$/kWh; 500<5MW 0.35CA$/kWh; >5MW 0.347 CA$/kWh • Accelerated Capital Cost Allowance		• Tax Credit for R&D • Call for tender or FIT	• R&D grants • KfW credits • Credits of regional government • FIT (20y): since 01.04.2012 - ≤10MW 13.5€¢/kWh (monthly degression) • Market Premium I		• Green certificates • Subsidy: construction/installation grants	• No support scheme available for plants coming into operation after Jan 2013 • FIT(30 years): P≤100kW: 48.8743 €¢/kWh; 10<P≤10MW: 46.3348€¢/kWh; 10<P≤50MW 25.4997€¢/kWh	• 100% depreciation deduction 1st year • Tax base reduction for depreciable assets • FIT (20y): 42¥/kWh

Examples of incentives to electricity generation – Renewable and non-renewable technologies (continue in the next page)

[200] Alberta, Ontario, Québec: HQ – Comparison of electricity prices 2011. France, Germany, Spain, Norway, Sweden, Japan: Key World Energy Statistics 2012. IEA

Technology	Alberta	Ontario	Quebec	France	Germany	Norway	Sweden	Spain	Japan
Hydro	• Offsets/Carbon Credits ~9.75CA$/MWh • Scientific Research and Experimental Development Investment Tax Credits • Accelerated Capital Cost Allowance • Climate Change Emissions Management technology fund • Research and Technology Program	• Refundable Tax Credit for qualifying R&D • Northern Energy Program • FIT (40y): <10MW 0.131CA$/kWh; 10MW<P<50MW 0.122 CA$/kWh • Accelerated Capital Cost Allowance	• Tax Credit for R&D • Green technology Demonstration Program • PAIE • Call for tender • Accelerated Capital Cost Allowance	• Tax Credit for R&D • FIT(base year 2007): 6.07€¢/kWh + prime 0.5 – 2.5 €¢/kWh (small plants) + prime winter 0 – 1.68 €¢/kWh; 15€¢/kWh in sea	• R&D grants • FIT (20y): 3.4-12.7 €¢/kWh • Market Premium I	• Tax allowance for R&D costs • Green Certificates • RENERGIX • ENOVA support programs • Nordic Investment Bank and Sparebank Vest credit	• Green certificates for hydro • Linear depreciation	• No support scheme available for plants coming into operation after Jan 2013 • FIT: <25y = 8.6565 €¢/kWh; >25y = 7.7909 €¢/kWh • Premium Tariff	• 100% depreciation deduction 1st year • Tax base reduction for depreciable assets • FIT (20y): 1MW≤P<30MW = 25.2¥/kWh
CCGT	• Scientific Research and Experimental Development Investment Tax Credits • Climate Change Emissions Management technology fund • Research and Technology Program	• Refundable Tax Credit for qualifying R&D	• Tax Credit for R&D • Green technology Demonstration Program PAIE	-	-	• Grants for R&D	-	-	-
Coal				-	• Funds for R&D in CO_2 storage Incentives in coal mining sector (guarantees & laying in)	-	-	-	-

Figure 100. Examples of incentives to electricity generation – Renewable and non-renewable technologies[201]

[201] All countries are members of REEEP (Renewable Energy & Energy Efficiency Partnership)

France	Germany	Norway	Sweden	Spain
Property Tax: • Land and Real Estate Tax (except PV) • Business Activity Tax (3% of company's added value) • Tax on Offices • French inland waterways Tax • Tax on nuclear installations • Tax on installed electric power	**Specific taxes and levies on electricity production:** • Nuclear fuel rod Tax 145 €/gr.	**Property Tax:** • 0.7% of appraised value • Municipal property tax	**Property Tax** • All technologies: 0.5% of appraised value • Wind 0.2% of appraised value • Hydro: 2.8% of appraised value	**Property Tax:** • Real Estate Tax
Operation Tax: • Global Tax on Pollutant Activities • Fees payable to water agencies • Contribution for the transitory regulated tariff for market adjustment (TaRTAM) • Fees on hydraulic works conceded		**Operation Tax: Hydro only!** • Natural resource tax 1.3 €¢/kWh	**Operation Tax**	**Operation Tax:** • Vary from provinces – e.g. tax for polluting gases into the atmosphere, tax on facilities that affect environment etc.
Other Taxes: • Excise duties (coal, natural gas, mineral oils)		**Other Taxes: Hydro only!** • Resource rent tax 30% of economic rent • License fee ~0.5 €¢/kWh • License power supply	**Other Tax:** • Nuclear Tax • Excise Tax: energy tax, sulphur tax, nitrogen fee	**Other Taxes:** • Waste water tax • Levies linked to the water • Tax on hydrocarbons • Tax on services rendered by the Nuclear Safety Council
Specific taxes and levies on distribution/transport of electricity: • Flat-rate taxation of very high-voltage electricity pylons • Tax on electrical transformers • Contribution to the "Fonds de Pérèquation de l'Electricité »(FPE)		**Specific taxes and levies on distribution of electricity:** • Municipal property tax • Fee to energy fund on grid tariff		**Specific taxes and levies on distribution of electricity:** • Vary for communities – e.g. tax on transmission and distribution activities etc.
Parafiscal levies on distribution/transport of electricity: • Contribution to the FACE (Fonds d'Amortissement des Charges d'Electrification)			**Parafiscal levies on transport of electricity**	**Parafiscal levies on distribution of electricity:** • Levy on the special use of the ground, sub-soil and air-space of the public thoroughfare • Levy on permits and authorizations to carry out works
Excise Taxes: • Contribution to the public utility of electricity • Consumption Tax on electricity	**Excise Tax:** • Electricity Tax • Tax on energy products (petrol, natural gas, coal etc.)	**Excise Taxes:** • Tax on electricity consumption (energy tax)	**Excise Tax:** • Tax on energy	**Excise Tax:** • Value Added Tax (VAT) • Special Tax on Electricity
Turnover Tax: • Value-Added Tax (VAT) • Contribution on transport and distribution of electricity	**Turnover Tax:** • Value-Added Tax (VAT)	**Turnover Tax:** • Value-Added Tax (VAT) 25%	**Electricity certificate system (REC)** • Value-Added Tax (VAT) 25%	**Turnover Tax:** • Value Added Tax (VAT)

Figure 101. Summary of taxes for electricity generation in the EU in 2011 (Eurelectric)

6.2 Alberta

In the early 1990s, Alberta began a review of its energy policies, and started to evolve from a regulated system to a competitive electricity market. In 1996, the Power Pool of Alberta was created, and the transmission system was opened to all eligible players. The Power Pool – including the wholesale hourly Energy Market, and the Ancillary Services Market[202] – is operated by the Alberta Electric System Operator (AESO). Under the new market structure, electricity generation and retail are liberalized. Players sell and purchase power in the Power Pool. Four agencies are responsible for various aspects of Alberta's electricity market: The Alberta Utilities Commission (AUC), the Alberta Electric System Operator (AESO), the Market Surveillance Administrator (MSA), and the Balancing Pool.

There are four transmission system owners in Alberta. AltaLink is the most important, serving almost 85% of the population, and owning more than 50% of the transmission system of the province. Electricity distribution companies include two regional private companies (ATCO Electric and Fortis Alberta), several municipal companies (EPCOR, ENMAX Calgary, etc.), and the rural electrification associations (REA). Customers can choose among a large number of electricity retailers[203].

Installed capacity in Alberta was 12.8 GW in 2010. The province has extensive mineral resources that determine the choices of generation technologies. Alberta accounts for approximately 50% of the coal and 70% of the gas production of Canada[204]. Nearly 86% of installed power in Alberta in 2010 consisted of thermal plants. Hydro and on-shore wind respectively amounted for 6.9% and 6.3%, and biomass for the remaining 1.1%.

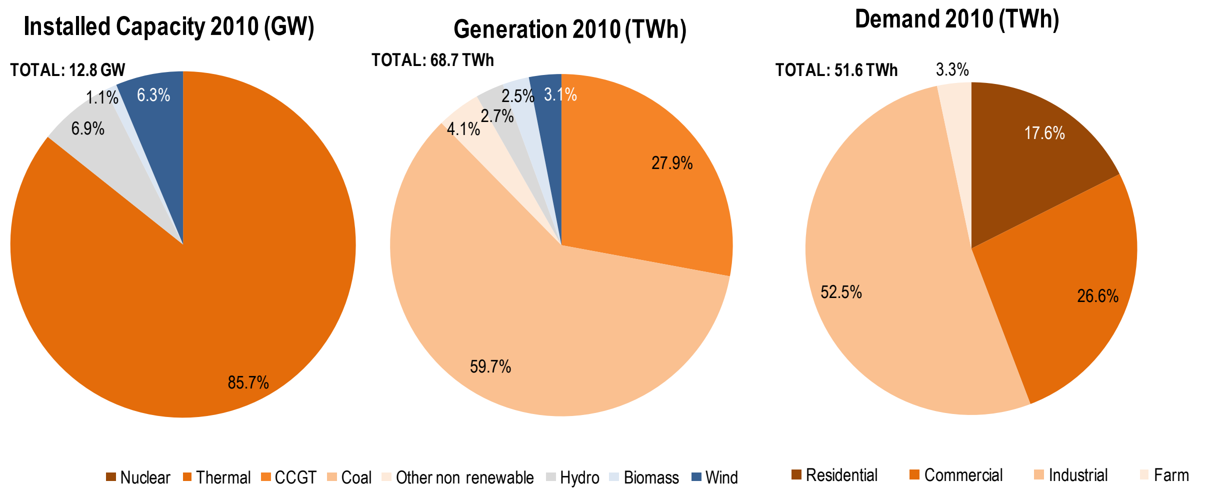


Figure 102. Alberta – Installed capacity (GW), generation (TWh) and demand (TWh) – 2010 [205 206]

[202] Source: Blakes Lawyers – Overview of Electricity Regulation in Canada

[203] Source: http://www.ucahelps.alberta.ca/energy-companies.aspx

[204] Source: Statistics of Canada, Energy Statistics Handbook

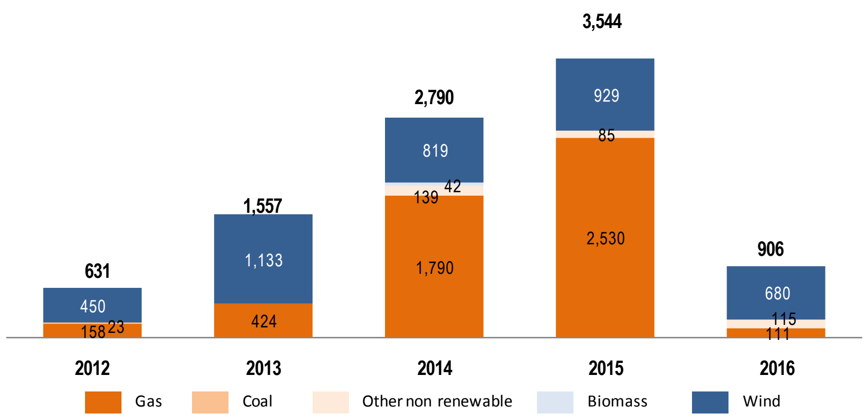
[205] Sources (Installed capacity and generation): Statistics of Canada,CANSIM: tables 127-0008 and 127-0009, available at: http://www5.statcan.gc.ca/cansim/a33?RT=TABLE&themeID=4012&spMode=tables&lang=eng. Source (Demand): Alberta Energy-Electricity statistics, available at: http://www.energy.alberta.ca/Electricity/682.asp

[206] Graphs will vary from country to country due to recent and original sources such as ministries and associations, row data from each province have not been aligned or consolidated as in most IEA reports. This view allows country specific analysis.

Generation: Most of the generation in Alberta in 2010 came from thermal plants (91.7%). The remaining 8.3% came from renewable sources (hydro, biomass, and on-shore wind).

Demand: In 2010, industrial consumption represented 52.5% of total electricity demand in the province. The second largest electricity consumer was the commercial sector, with 26.6% of total demand. The residential sector was the third largest consumer with 17.6%. Significant population growth and industrial stimuli are expected to significantly increase power demand in the near future in Alberta[207].

Generation projects: As shown in Figure 103, more than 9 GW of new generation capacity are being proposed for development in Alberta in the next 4-5 years. The main source of generation will continue to be gas, with 5.0 GW of new installed capacity. The rest will be on-shore wind, with 4.0 GW of planned new capacity[208].



Technology	Cumulative Proposed Installed Power (2012-2016)
Gas	5,013
Coal	23
Other non renew	339
Biomass	42
Wind	4,011
TOTAL	**9,428**

Figure 103. Alberta – Proposed capacity projects (MW)[209]

Electricity price formation: The electricity generated in Alberta and not consumed on site (self-generation), as well as the power imported from locations outside of Alberta are traded in the Power Pool[210].

Alberta´s market prices are somewhat volatile, with significant fluctuations between seasons and between hours of the day. In the last 2-3 years, electricity prices have been slightly lower than those of the preceding 3-4 years. The underlying drivers have been the constant change in the demand and supply dynamics, and the evolution of other factors such as natural gas prices. In 2011, power prices increased due to lower availability of coal-fired plants, coupled with the growth of power demand in the province[211].

Incentives to generation: In Alberta the main incentive to renewable generation is offsets. Offsets or carbon credits enable emitters to compensate their excess carbon emissions with emission performance credits purchased from producers of “clean” electricity. Three possibilities exist to compensate emissions (1) buy emission performance credits from other regulated companies that go beyond their requirements; (2) pay into the

[207] Source: Statistics of Canada, 2010 catalogue 57-202 Electricity Generation, Transmission and Distribution

[208] Source: Alberta Electric System Operator, Prysma analysis

[209] Source: Alberta Electric System Operator. Prysma analysis

[210] Each day by 12:00 pm producers and importers present their offers for the next seven days in increments of one-hour periods. Generators are required to offer all of their available energy to the market at a price between CA$0.00 and CA$999.99 per megawatt hour; however, they are able to change their offer price up to two hours prior to the delivery time. Offers and demand are cleared in the resulting merit order curve. The highest offer price that is dispatched by the system operator to satisfy the demand sets the system marginal price.

[211] Source: AESO web page

technology fund at a set price of 15 CA$/t$CO_2$ (15 US$/t$CO_2$); and (3) buy offsets in the market[212]. Offsets increase the revenue of eligible generation plants.

Another type of certificate relevant to a few producers in Alberta is RECs (Renewable Energy Credits). RECs are certificates that can be sold in the WECC (Western Electricity Coordination Council-USA) area. RECs prices have been higher than offset prices (about 30 CA$/MWh (30 US$/MWh))[213], and could in theory significantly improve the business case of Albertan plants. However, foreign owned generation plants (non-USA based) are subject to restrictions. It appears that very few Canadian plants have been able to use RECs[214].

The following table summarizes some of the most relevant incentives to renewable and non-renewable generation in Alberta:

<table>
<tr><th>TECHNOLOGY</th><th>INCENTIVES</th></tr>
<tr><td>ON-SHORE WIND</td><td>Offsets ~9.75 CA$/MWh (9.75 US$/MWh)[215]
Other
Scientific Research and Experimental Development Investment Tax Credits
Climate Change Emissions Management technology fund
Research and Technology Program
Accelerated Capital Cost Allowance</td></tr>
<tr><td>OFF-SHORE WIND</td><td>n.a.</td></tr>
<tr><td>PHOTOVOLTAIC</td><td rowspan="2">Offsets ~9.75 CA$/MWh (9.75 US$/MWh)
Other
Scientific Research and Experimental Development Investment Tax Credits
Climate Change Emissions Management technology fund
Research and Technology Program
Accelerated Capital Cost Allowance</td></tr>
<tr><td>HYDRO POWER</td></tr>
<tr><td>CCGT</td><td rowspan="2">Scientific Research and Experimental Development Investment Tax Credits
Climate Change Emissions Management technology fund
Research and Technology Program</td></tr>
<tr><td>COAL</td></tr>
</table>

Also, REEEP (Renewable Energy & Energy Efficiency Partnership) – applicable to all technologies

Figure 104. Alberta – Incentives to electricity generation (example, not comprehensive)

6.2.1 Detailed business cases – Alberta / On-shore wind

The range of generation costs obtained from simulations of new on-shore wind plants in Alberta is 70-100 US$/MWh. Plants with low capital costs and advantageous operating conditions would be at the lower end of the span. That is, large plants (75-100 MW), with high capacity factors (30-35%), and low financing rates (4-6%) would display generation costs 20-25% lower than mid-sized plants (50-70 MW), with average capacity factors (~25-30%), and higher discount rates (7-10%).

[212] Offsets average price used in calculation are 9.75 CA$/MWh as "starting point". The price may vary.

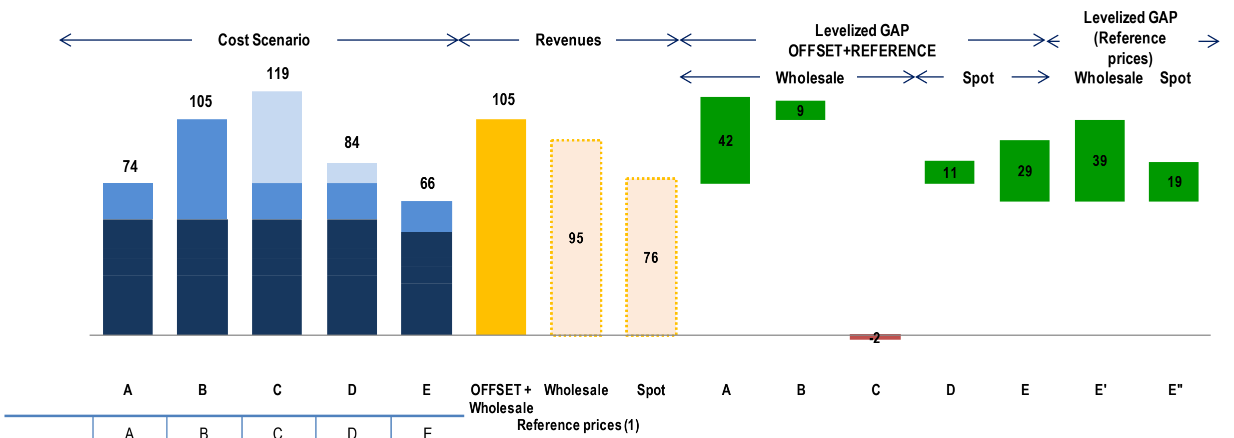
[213] Source: Prysma interviews

[214] Sources: FMC LAW – The Impact of Offsets and REC's on the Economics of Wind Projects in Alberta. Data from Bloomberg and three interviews indicate that currently only one company "Greengate" in Alberta is able to trade RECs with the USA.

[215] Source: Data from Prysma interviews

The reference compensation for on-shore wind plants – consisting of market prices + offsets – has been estimated at 105 US$/MWh. Investors able to fine-tune their plants may obtain enough revenue-cost spread to attain reasonable rates of return. However, the business case of generation is very sensitive to the capacity factor of the plants. With capacity factors above 25% it is possible to define a profit making on-shore wind project. But at the current market and offset prices, average capacity factors below 25% would result in loss making propositions. Turning around the business cases of the average plants would require increasing their potential revenues, attaining higher market prices, or higher offsets prices.

Plants with financing rates higher than 12% (case B in Figure 105) result in profitable ventures if they can access the highest ranges of revenues (market prices + offsets) in a consistent basis during the life of the plant.



	A	B	C	D	E
Capacity factor	35%	35%	20%	30%	30%
DR	5%	12%	5%	5%	5%
Size-MW	75	75	75	75	100

Project operating results

	A	B	C	D	E	E'	E"
NPV (M$)	90	5	-13	13	69	97	41
IRR	14%	14%	5%	7%	12%	14%	10%

Impact of technology
Cost of fuel
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP

(1) Reference wholesale price 2011. Reference spot price 2011

Figure 105. Business cases – On-shore wind in Alberta (2012 US$/MWh)

In summary, at the current market conditions and incentive system conditions in Alberta, on-shore wind plants, may provide attractive returns to investors.

This favorable situation may continue in the future. On the one hand, the quality of wind resources in Alberta is quite good in many sites. In addition, the province has good growth perspectives, with annual growth rates of 3.0 - 3.5% expected in the next 10 years[216]. This may translate in the future in higher electricity demand. It may also contribute to increasing the electricity market prices in the region, and allow plants to reach higher capacity factors. The combined impact of these factors is likely to positively affect the revenue-cost gap of on-shore wind generation in the province.

6.2.2 Detailed business cases – Alberta / CCGT

The costs of gas-fired generation in Alberta are the lowest within the regions in scope of the study (~55-80 US$/MWh). Alberta's extensive gas resources (shale gas) drive down fuel costs. Estimated gas prices in the

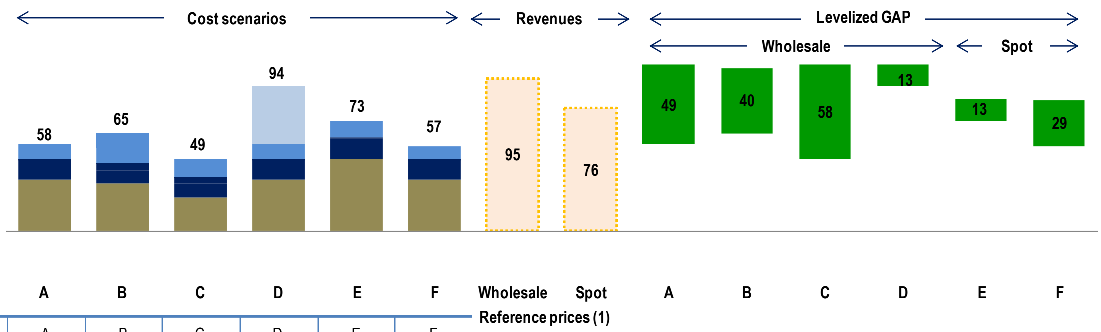
[216] Source: CIBC World Markets

province were in the range of 4.0-4.5 US$/MMBtu: 40-60% lower than those of plants operating in regions with higher gas costs.

The simulations conducted yield NPVs of 700-1,500 M$ and IRRs of 14-30% for gas-fired plants with good market and operating conditions. The results are very robust, and tend to be stable with large variations of other inputs:

- Even with a 50% increase in the fuel price, the business case of generation is still attractive for some CCGT plants.
- Plants with relatively low capacity factors could generate profits for investors in plants with capital costs in the lower ranges. Plants with low capacity factors (above 30%) have positive IRRs and NPVs. This means they could generate positive profits over the lifetime of the plant. But their business cases would be rather thin. Investors may consider other business alternatives with higher margins.

Low gas prices also indirectly affect the business case of CCGT plants in Alberta through a reduction of the average financing rates of this technology in the region. (3-10% in Alberta versus 4-13% in regions with higher gas costs). Assurance of abundant fuel supply at advantageous prices significantly contributes to reduce the perceived risk of the technology, and results in lower financing rates (see Section 2.4).



	A	B	C	D	E	F
Capacity factor	75%	75%	75%	30%	75%	75%
DR	6.5%	10%	6.5%	6.5%	6.5%	6.5%
Size-MW	400	400	400	400	400	800
Fuel Cost	Avg.	Avg.	-30%	Avg.	+50%	Avg.

Project operating results

	A	B	C	D	E	F
NPV (M$)	1,284	736	1,529	88	298	1,467
IRR	25%	25%	28%	9%	12%	19%

Impact of technology
Cost of fuel
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP
(1) Reference wholesale price 2011. Reference spot price 2011

Figure 106. Business cases – CCGT in Alberta (2012 US$/MWh)

Although the specific figures obtained in the simulations may change in the future, gas-fired plants are likely to maintain advantageous costs in the medium and long term in Alberta.

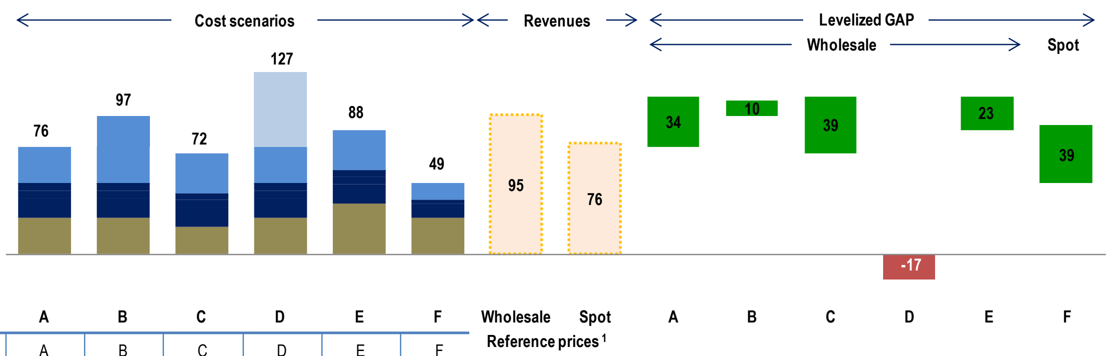
6.2.3 Detailed business cases – Alberta / Coal

Alberta is a region rich in coal resources. This results in security of supply of coal and contributes to stabilize the prices of this commodity. Ranges of market prices of coal in Alberta are comparable to those of other North American locations (~2.2 US$/MMBtu). However, a number of coal plants in Alberta are fed with mine-to-mouth coal, at a cost lower than the prevailing market prices. Cost of mine-to-mouth coal is not publicly available. But interviews have indicated that the prices of coal for these plants could be at least 10-20% lower than the prices of coal in the free market (~1.6-1.8 US$/MMBtu). In addition, coal plants in Alberta display high capacity factors (66% average in 2010), further increasing the attractive of investments in this technology.

Low fuel costs and high plant capacity factors would offset the impact of the higher capital costs of new coal plants discussed in Section 5.5 (1,000 – 4,000 US$/MW). As a consequence, this technology may yield attractive business cases if the plants operate in good conditions. Large plants, with capacity factors ~50-70%, that use coal at advantageous prices present attractive business cases (positive income, 10-15% IRR, 250-750 US$/MWh NPVs).

Plants with less attractive characteristics would result in negative business cases.

- Plants with capacity factors lower than 45% are unlikely to be profitable at the reference prices of electricity used in simulations for Alberta, even when burning low priced coal.
- Large increases in the cost of coal (>30-35% over the reference used) may make a plant unprofitable, if the plant receives only the spot market price of electricity.
- Discount rates higher than 10-12% also result in unprofitable new coal-fired projects.



	A	B	C	D	E	F
Capacity factor	60%	60%	60%	30%	60%	60%
DR	7%	11%	7%	7%	7%	7%
Size-MW	400	400	400	400	400	600
Fuel Cost	Avg.	Avg.	-20%	Avg.	+50%	Avg.

Project operating results

	A	B	C	D	E	F
NPV (M$)	641	67	741	-290	390	1,217
IRR	13%	13%	14%	5%	11%	21%

Impact of technology
Cost of fuel
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP

(1) Reference wholesale price 2011. Reference spot price 2011

Figure 107. Business cases – Coal in Alberta (2012 US$/MWh)

In the future, emission costs may contribute to deteriorate the business cases of coal-fired plants in the region. Generation plants in Alberta are required to reduce emissions gradually or to face a penalty. Emission costs could increase the cost of generation by 10-15%, enough to significantly deteriorate the results of the average coal-fired plant.

In summary, at the present, ample availability of local coal at attractive prices, and high capacity factors result in good opportunities for investment in coal-fired plants in Alberta. In the future, increasing costs of emissions may make it difficult for investors to attain high levels of profitability from this technology.

6.2.4 Alberta – Lessons learned

Support policies are essential to ensure the development on-shore wind in Alberta, due to the very low cost of competing generation technologies such as CCGT. The current scheme, based on offsets to clean generation, appears to provide enough incentive to investors in on-shore wind. Simulations show that new plants could deliver margins high enough to generate interest in developers in this technology.

Current policies seem to be working. If Alberta policy makers are satisfied with the current pace of development of new RET in their region, it may be advisable to avoid significant changes to the existing scheme. Marginal adjustments to the scheme could consist of:

- More vigorous broadcasting of the commitment to renewable generation, for instance through the usage of qualitative tools, such as announcement of studies to improve the rewards to wind generation, or of broadcasts of the successful development of on-shore wind in the province. Experience shows that these announcements may reduce discount rates, and increase the pool of interested investors.
- Implement actions to reduce the permission process for on-shore wind. This process is viewed by some investors as long and complex, and may be discouraging the implementation of a number of generation projects in the Albertan market[217].

If Albertan policymakers desired to significantly and quickly increase the proportion of on-shore wind generation in the region, simulations show that modifying or changing the existing support scheme may increase the speed in RET investment. Two mechanisms could be used to significantly stimulate the incorporation of new on-shore plants:

- Increasing the penalties for non-compliance with the gradual reduction of emissions, and extending the program. This measure may increase the price of offsets, and therefore the rates of return of the average on-shore wind plants. This action would not disrupt the existing structure of incentives, but it would affect the power mix and potential electricity prices in the region.
- Changing the structure of the current incentive system. For instance, establishing a FIT at 100-110 US$/MWh or higher would significantly improve the business case of on-shore wind generation and the associated interest of investors. However, this action represents a significant departure from the structure of current policies. It should be considered only if a significant increase of installed on-shore wind power, beyond by the goals stated by the long term plans of the province, is desired at some point in the future.

6.3 Ontario

The electricity market in Ontario reached its current structure through a number of government acts and events. Today Ontario has a hybrid market model that combines regulation and competition. The Electricity Act of 1998 divided Ontario Hydro, the former incumbent, into five separate companies. In 2002, the Ontarian government liberalized the wholesale and retail power markets, but electricity prices and distribution rates were frozen-up and some of these characteristics remain today[218]. In 2009, under the Green Energy Act, the government of Ontario implemented a feed-in tariff (FIT) program to stimulate the development of renewable energy in the province.

A large number of electricity producers in Ontario operate under long-term electricity contracts with the Ontario Power Authority. The Ontarian wholesale market mostly enables the province to determine the most efficient dispatch order for the supply required to satisfy demand. The market is regulated and structured by a number of actors: the Independent Electric System Operator (IESO), the Ontario Electricity Financial Corporation (OEFC), the Electricity Safety Authority (ESA), the Ontario Power Authority (OPA), the Ontario Energy Board (OEB), and the Ministry of Energy.

Transmission and distribution are regulated by the provincial authority. Two of the most important companies in the electricity sector in Ontario are owned by the province: Ontario Power Generation Inc. (OPG), which generates

[217] Source: Interviews
[218] Source: Blakes Lawyers – Overview of Electricity Regulation in Canada

roughly 70% of the electricity in Ontario; and Hydro One Networks, which owns approximately 97% of the transmission grid of the province. About 70 public and private licensed distribution companies supply electricity in Ontario[219]. Ontario Power Generation is the most important power producer.

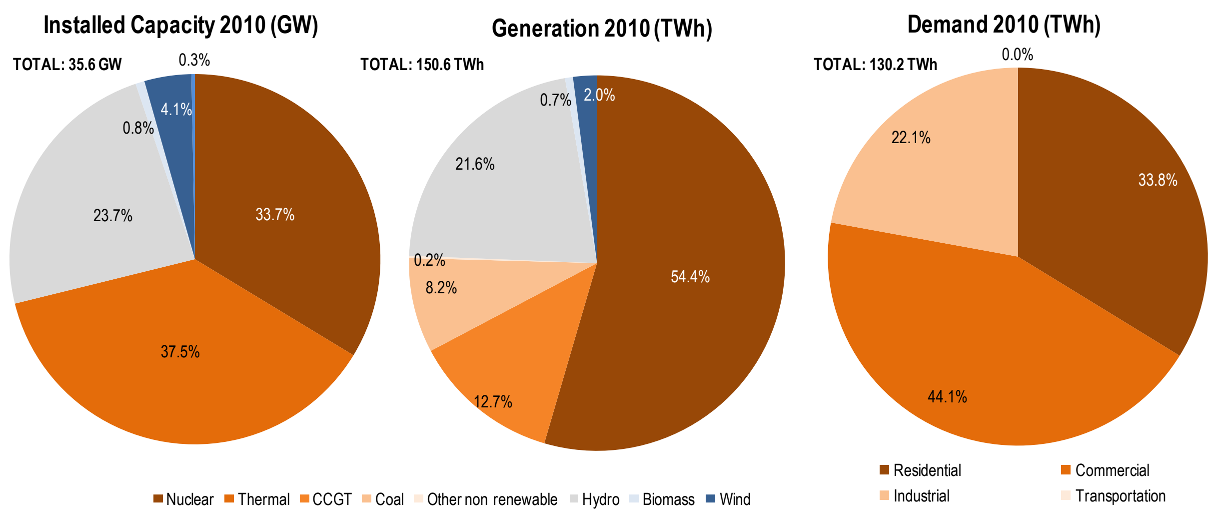


Figure 108. Ontario – Installed capacity (GW), generation (TWh) and demand (TWh) – 2010[220]

Installed capacity in Ontario was 35.6 GW in 2010. Ontario is one of the two provinces in Canada with nuclear installed capacity[221]. Nuclear power accounted for 33.7% of the total (3 plants with total installed capacity ~13.0 GW). Thermal plants – based on coal and natural gas – accounted for 37.5% of total installed capacity. The rest consisted of renewable sources, with hydro representing 23.7%, on-shore wind 4.1%, biomass 0.8%, and solar PV 0.3%.

Generation: In 2010, electricity production in Ontario came mainly from nuclear (54.4%), hydro (21.6%) and thermal plants (21.1%). The rest (≈3%) came from renewable sources (wind, biomass and solar).

Demand of electricity in Ontario reached ~130 TWh in 2010. The commercial sector accounted for 44.1% of total consumption. As in other provinces, the global economic recession has contributed to a decline in electricity demand in Ontario since 2009. Power demand is expected to recover in the next years due to significant population and economic growth[222].

Generation projects: The province is planning to build a variety of generation plants, both renewable and non-renewable. It is one of the few governments that appear to be planning to build nuclear plants. Two additional units should be commissioned in the future[223]. Ontario has decided to eliminate coal generation by the end of 2014. Figure 109 summarizes the short term generation plants in the province.

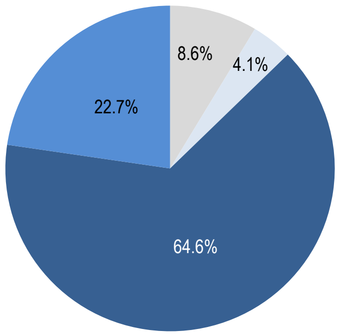
[219] Source: IESO – Power System

[220] Source: Statistics of Canada, CANSIM: tables 127-0008 and 127-0009, available at: *http://www5.statcan.gc.ca/cansim/a33?RT=TABLE&themeID=4012&spMode=tables&lang=eng*

[221] Source: Canadian Nuclear Association. The other province is New Brunswick. Quebec has recently shut down (Dec 2012) its only plant

[222] Source: Statistics Canada. 2010 catalogue 57-202 Electricity *Generation, Transmission and Distribution*

[223] Source: Ministry of Energy. Ontario's Long-Term Energy Plan



Technology	Projects Planned
Hydro	656
Bio-Energy	308
Wind	4,902
Solar PV	1,721
TOTAL	**7,587**

Figure 109. Ontario – Planned capacity projects (MW)[224]

Electricity price formation: Wholesale electricity prices in Ontario follow a similar pattern to those in Alberta. They tend to be either the same, or slightly lower. The Ontarian market is less volatile than Alberta's [225].

Incentives to generation: In 2009 Ontario launched a feed-in tariff (FIT) program to stimulate the development of renewable energy technologies, and to attract investment. In March 2012, the tariff levels were reduced. Solar ground mount will receive 34.7–44.5 CA$¢/kWh (34.7–44.5 US$¢/kWh), depending on the size of the installation. The tariff for wind was set at 11.5 CA$¢/kWh (11.5 US$¢/kWh). Hydro facilities smaller than 50 MW and bigger than 10 MW will receive 12.2 CA$¢/kWh (12.2 US$¢/kWh). Part of the tariff increases annually with the consumer price index (CPI) of the province (20% of the tariff for wind and waterpower projects, and 0% of the tariff for solar projects)[226].

The following table summarizes the most relevant incentives for electricity generation in Ontario.

TECHNOLOGY	INCENTIVES
ON-SHORE WIND	**Feed-In-Tariff** (20 years) • 0.115 CA$/kWh (0.115 US$/kWh) **Other** • Refundable Tax Credit for qualifying R&D • Northern Energy Program • Accelerated Capital Cost Allowance
OFF-SHORE WIND	n.a.
PHOTO-VOLTAIC	**Feed-In-Tariff Ground-mount** (20 years) • ≤10kW 0.445 CA$/kWh (0.445 US$/kWh) • 10 kW<P≤500kW 0.388 CA$/kWh (0.388 US$/kWh) • 500kW<P≤5MW 0.35 CA$/kWh (0.35 US$/kWh) • P>5MW 0.347 CA$/kWh (0.347 US$/kWh) **Other** • Refundable Tax Credit for qualifying R&D • Northern Energy Program • Accelerated Capital Cost Allowance

224 Source: Projects committed but not yet online (January 2013). Source: OPA. Prysma analysis

225 Source: National Energy Board, Canada

226 Source: McMillan. Ontario´s green energy feed-in tariff program re-launched and revised

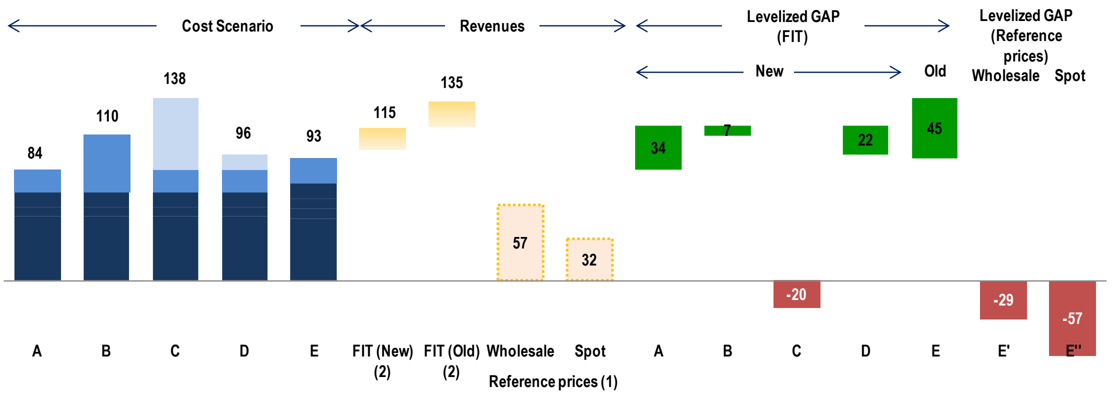
TECHNOLOGY	INCENTIVES
HYDRO POWER	**Feed-In-Tariff** (40 years) • P≤0MW 0.131 CA$/kWh (0.131 US$/kWh) • 10MW<P≤50MW 0.122 CA$/kWh (0.122 US$/kWh) **Other** • Refundable Tax Credit for qualifying R&D • Northern Energy Program • Accelerated Capital Cost Allowance
CCGT	• Refundable Tax Credit for qualifying R&D
COAL	

Also, REEEP (Renewable Energy & Energy Efficiency Partnership) – applicable to all technologies

Figure 110. Ontario – Incentives to electricity generation (example, not comprehensive)

6.3.1 Detailed business cases – Ontario / On-shore wind

Figure 111 displays the results of the simulations of the business cases of on-shore wind plants in Ontario. These results support the perception that incentives are necessary to support on-shore wind, given the low levels of market prices of electricity prevailing in the province (32-57 US$/MWh were used in the simulations).



	A	B	C	D	E
Capacity factor	35%	35%	20%	30%	30%
DR	3.5%	8%	3.5%	3.5%	3.5%
Size-MW	100	100	100	100	150

Project operating results

	A	B	C	D	E	E'	E''
NPV (M$)	102	1	-62	47	182	-162	-291
IRR	9%	9%	1%	7%	10%	-	-

Impact of technology · Cost of fuel · Impact of capacity factor · Impact of DR · Revenues · Direct impact of policies · Positive Levelized GAP · Negative Levelized GAP

(1) Reference wholesale price 2011. Reference spot price 2011
(2) Adjusted to CPI (20%)

Figure 111. Business cases – On-shore wind in Ontario (2012 US$/MWh)

The incentive scheme has been recently revised. In 2012, the Ontario government reduced the FIT levels from 135 US$/MWh to 115 US$/MWh. The objective of the FIT reduction was to adapt incentives to the realities of power generation in the province. The FIT revision has put pressure on investors in new on-shore wind plants that have now to define profitable projects at revenues 15% lower than those prevailing in recent years.

- With the 2011 FIT, plants operating at medium to high capacity factors attained positive business cases (10-12% IRRs and 150-175 MUS$ NPVs). Investors appeared to be sufficiently rewarded.
- The 2012 FIT reduces the potential profits of on-shore wind plants. However, the compensation provided by the scheme may still result in positive business cases for plants operating in conditions which position them in the medium-low ranges of cost (Size 100-150 MW, 30-35% capacity factor, and 3-7% discount rate). Plants with capacity factors higher than 20% show positive income and NPV with the new FIT. With capacity factors lower than 20%, the business cases of the majority of new on-shore wind plants are very

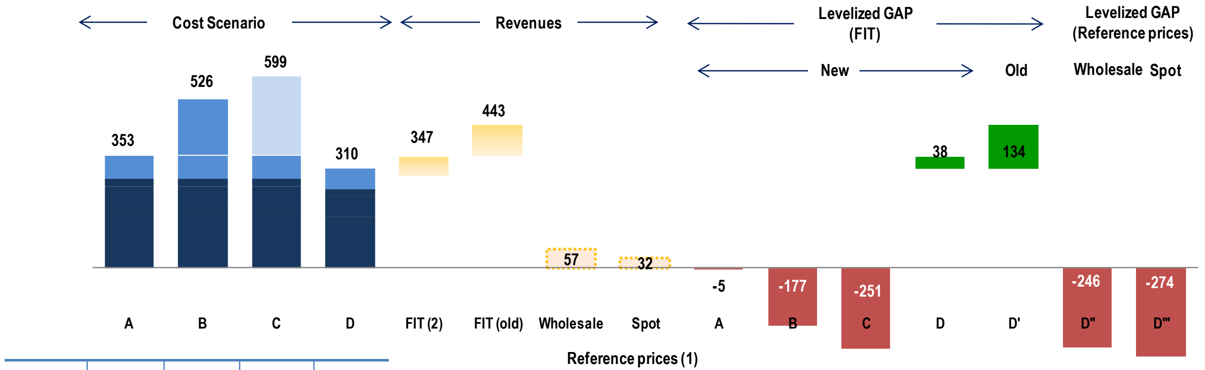
thin. Plants operating at low capacity factors would not break-even. Increasing the plant size has a small effect in the business case (increasing the size of a plant from 100 to 150 MW yields cost reductions of only 3-5 US$/MWh).

In these circumstances, investors in on-shore wind in Ontario will need to be very careful, focusing only on projects with low capital costs, and likely to operate above average capacity factors (higher than 20%)[227].

6.3.2 Detailed business cases – Ontario / Solar PV

At the reference prices of electricity used in the simulations, even the most advantaged solar PV plants require incentives to attain positive business cases.

In 2012, the government of Ontario reduced the FIT for solar ground mount above 5 MW from 443 US$/MWh to 347 US$/MWh, and modified the size ranges of eligible plants. These policy changes appear to be putting significant pressure in the potential profitability of new solar PV plants in the region.



	A	B	C	D
CF	17%	17%	10%	22%
DR	3.5%	10%	3.5%	3.5%
Size-MW	55	55	55	5

Project operating results

	A	B	C	D	D'	D''	D'''
NPV (M$)	-28	-115	-166	2	13	-30	-33
IRR	3%	3%	-	5%	9%	-	-

Impact of technology
Cost of fuel
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP
(1) Reference wholesale price 2011. Reference spot price 2011
(2) Not adjusted to CPI

Figure 112. Business cases – Solar PV in Ontario (2012 US$/MWh)

Simulations show that, with the previous tariff levels (before 2012), solar PV plants positioned in the medium-low ranges of cost (5MW, with 17-20% capacity factors, and benefiting from low discount rates 3-15%) could turn a profit. They attained NPVs up to 5-20 MUS$ and 7-10% IRRs.

The new tariffs approved by the provincial government significantly reduce the revenue-cost gap of new solar PV plants. The majority of new solar PV plants operating in the current market situation, with LCOE ranges of 350-500 US$/MWh, would not be able to turn a profit.

Best-in-class solar PV projects (low capital cost plants, with capacity factors equal or higher than 20%) can break even, but attain negative NPV. This means that the plants do not yield profits high enough to compensate investors at the levels required by the risks associated to this technology. (IRRs at 3-5%, far lower than the 8-10% quoted as reasonable in sector interviews).

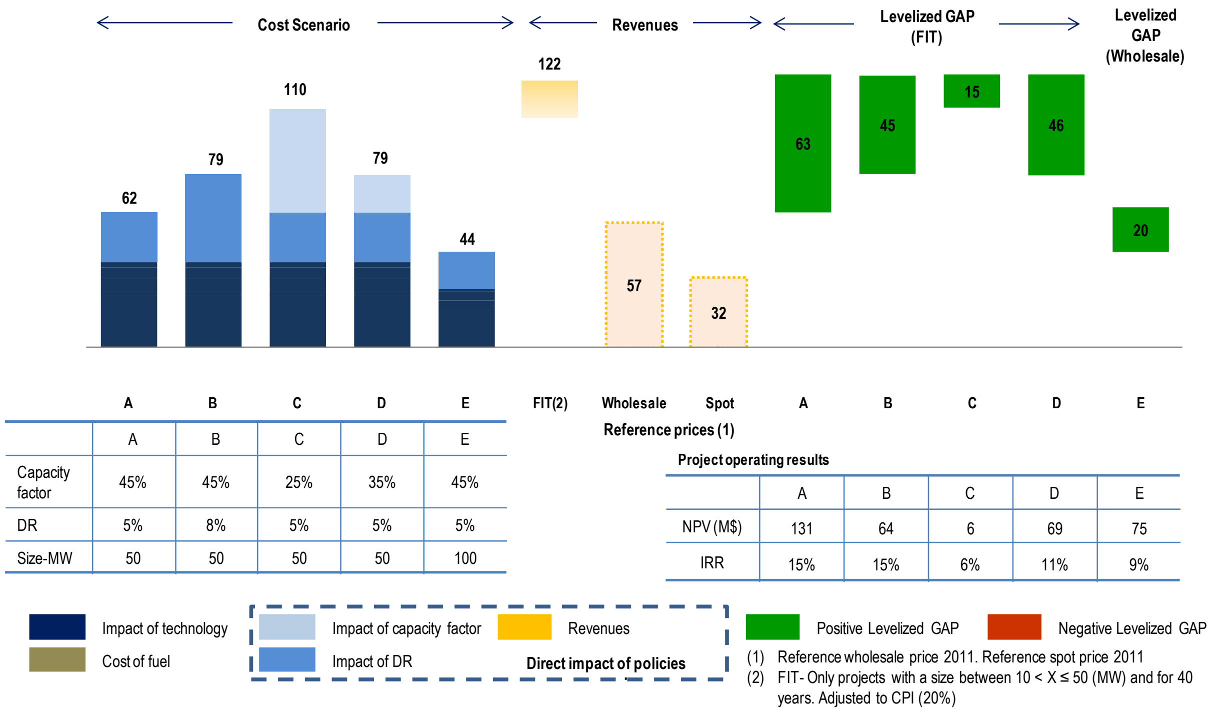
Lower capital costs of solar PV would be required to operate under the current incentive system in Ontario. Interviews with solar PV project developers in other countries suggest that breakthroughs in solar module

[227] In 2010 average capacity factor for wind generation in Ontario was 21% - see Figure 43

technology, and improvements in manufacturing processes could reduce capital costs of solar PV by 30-50% in the next 3-4 years. At these low ranges of costs, defining profitable solar PV projects in Ontario at the current FIT levels would be possible. However, it is not clear how many plants may reach in the short term the design characteristics, and operating conditions necessary to provide a reasonable rate of return with the prevalent scheme in the region.

6.3.3 Detailed business cases – Ontario / Hydro

Ontario has a lower hydro potential and quality of resource than other Canadian regions, for instance Quebec. Simulations yield LCOE ranges of 60-110 US$/MWh for this region/technology pair. The results are very variable, depending on the specific plant (location, transmission costs, size of the plant, capacity factors, etc.).



	A	B	C	D	E
Capacity factor	45%	45%	25%	35%	45%
DR	5%	8%	5%	5%	5%
Size-MW	50	50	50	50	100

	A	B	C	D	E
NPV (M$)	131	64	6	69	75
IRR	15%	15%	6%	11%	9%

Figure 113. Business cases – Hydro in Ontario (2012 US$/MWh)

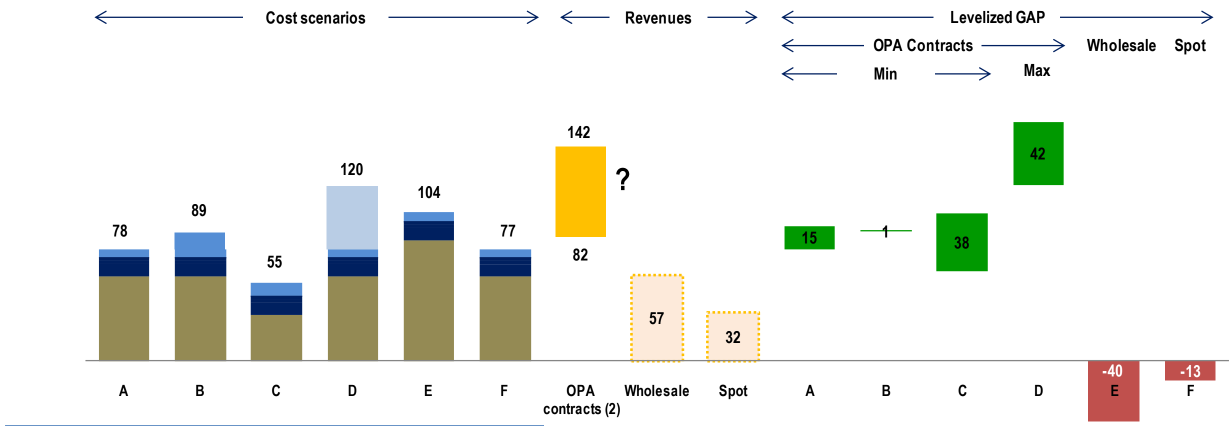
The current FIT for hydro is 122 US$/MWh. This incentive is provided only during the first 40 years of operation, and only to plants under 50 MW. In contrast with the FIT for solar, the FIT for hydro was not modified in 2012. The business case of hydro is very dependent on whether the plant receives incentives or not.

- Plants below 50 MW, operating at capacity factors above 35% display positive business cases, with 8-15%IRRs and 50-100 MUS$ NPVs. This positive outlook would hold even with relatively high discount rates. The business case for small plants is positive with discount rates up to 12%.
- New hydro plants larger than 50 MW may find it difficult to deliver attractive business cases. Best-in-class projects, with capacity factors above 45%, receiving prices in the higher part of the reference ranges could be profitable. But the plant must ensure it receives these higher prices during its whole lifetime (> 40 years).

The profitability of a hydro project in Ontario is by no means ensured. Investors must conduct careful assessments before committing to a given project. However, it seems that the tariff levels defined in the region may be appropriate to compensate investors in new small hydro plants.

6.3.4 Detailed business cases – Ontario / CCGT

Ontario is transitioning out of coal as power generation technology. This may increase the importance of gas as a dispatchable technology, flexible and easier to build and not dependent on the weather patterns as hydro. In fact, some coal-fired plants in Ontario may be converted in gas-fired plants (Thunder Bay plant, temporarily suspended)[228].



	A	B	C	D	E	F
Capacity factor	75%	75%	75%	25%	75%	75%
DR	5%	11%	5%	5%	5%	5%
Size-MW	400	400	400	400	400	800
Fuel Cost (3)	High	High	Low	High	High +50%	High

Project operating results

	A	B	C	D	E	F
NPV (M$)	430	-19	1,162	383	-1,339	-928
IRR	12%	12%	20%	11%	-	-

Impact of technology; Cost of fuel; Impact of capacity factor; Impact of DR; Revenues; Direct impact of policies; Positive Levelized GAP; Negative Levelized GAP

(1) Reference wholesale price 2011. Reference spot price 2011
(2) Ontario Power Authority, Cost Disclosure - Generation Supply
(3) Ranges

Figure 114. Business cases – CCGT in Ontario (2012 US$/MWh)

As discussed in Section 5.5, gas generation is highly dependent on the prices of gas. The natural gas used in the region is imported mostly from Saskatchewan, Alberta and British Columbia. Gas prices in Ontario are on average higher than the prices prevalent in Alberta, but still quite low. The range of gas price used in the simulations was ~4-7 US$/MMBtu[229].

New CCGT plants operating at the prices of generation defined by the Ontarian electricity market (32-57 US$/MWh have been used in the simulations), display poor business cases, as indicated by the red bars representing the GAP in the E and F cases in Figure 114. Investors would not receive enough compensation to cover LCOEs in the range of 75-110 US$/MWh.

However, CCGT plants in Ontario sell the electricity produced under long-term contracts with the Ontarian Administration. The prices awarded to each plant are not in the public realm, but estimates have yielded ranges of potential prices of 82-142 US$/MWh[230]. At this compensation levels, CCGT plants should be able to reap profits, and compensate investors.

[228] Source: http://www.thestar.com/business/article/1312865–Ontario-coal-burning-power-plants-to-close-this-year

[229] There is uncertainty about the gas prices actually paid by CCGT plants in Ontario. To simulate a wide range of possibilities, in case C the gas price used was 4 US$/MMBtu (similar to the price used in Alberta simulations)

[230] Source: Ontario Power Authority – Cost Disclosure – Generation Supply

If market prices increase in the future at ~75-90 US$/MWh, and average capacity factors increase to 60-75%, CCGT plants could theoretically operate at market prices in Ontario. Plants with 70% or higher capacity factors, compensated at 75 US$/MWh would yield 7-10% IRRs, and positive NPVs at the current discount rates in the province. Such a large increase of revenues may be possible only for plants that benefit from additional revenues (balancing revenues or other sources of revenue).

6.3.5 Ontario – Lessons learned

Policies aiming to develop **on-shore wind, solar PV and small-medium hydro** in Ontario consist of FITs awarded to eligible plants. The FIT levels have recently been changed in order to adapt the incentives provided to the realities of generation in the province. This has resulted in a reduction of the potential margins for investors in RET technologies, and in a change of the outlook of the business cases of different RET.

- The revised on-shore wind tariff provides positive business cases and reasonable margins for most projects operating at average conditions (80-150 MW, 30-35% capacity factor and 3-8%discount rate).
- The new solar PV tariff may be too low for the average large solar PV (5-50 MW, 17-20% capacity factor and 3-8% discount rate), not providing a positive business case to investors
- The tariff applicable to small hydro projects (5-50 MW, 35-45% capacity factor and 3-8%discount rate) does provide enough incentive to turn a profit during the life of good to best-in-class projects.

As a consequence, if Ontarian policy makers desired to significantly increase the installed capacity of new RET, a revision of the levels and provisions applicable of the last FIT enacted in the region might be recommendable.

- It would not be necessary to modify the current scheme for on-shore wind, and hydro generation.
- To interest investors, solar PV tariffs could be increased to 380-420 US$/MWh. These levels would provide reasonable rates of return to best-in-class plants (5 MW, 17-20% capacity factor and 3-15% discount rate). The proposed rates could be reduced in the near future, when technology breakthroughs result in lower costs of solar PV generation. With the forecast cost reductions, solar PV tariffs at 325-350 US$/MWh would still provide attractive returns to the most technologically advanced plants.

6.4 Quebec

Most of the power production of the province is based on hydro (96% in 2010). But Quebec also counts with an array of other generating technologies; including one nuclear plant, thermal plants and other RET plants (on-shore wind and biomass). The prices of electricity in Quebec are some of the lowest of Canada. In 2012 Quebec was responsible for approximately 50% of all net Canadian electricity exports to the US.

La Régie de l'Énergie is the regulator of the Quebecoise electricity and gas markets. The electricity sector in Quebec is dominated by Hydro Quebec, a government-owned company. Hydro-Quebec Équipment, which designs, builds and refurbishes generating plants and transmission facilities, is responsible for infrastructure construction for Hydro-Quebec. The largest power generator is Hydro-Quebec Production, with 90% of the total installed capacity in Quebec in 2010. Hydro Quebec Production sold approximately 165 TWh of electricity (heritage pool) in 2010 to Hydro Quebec Distribution at a price fixed by law (Loi sur la Régie de l'Énergie). Hydro Quebec Distribution distributes most of the electricity in the province, excluding that of some territories where the exclusive distributor is a cooperative, municipal or private distributor[231]. Transmission is operated by Hydro Quebec TransÉnergie,

[231] Source: Blakes Laywers – Overview of Electricity regulation in Canada

which has the most extensive transmission system in North America, comprising 33.360 km of transmission lines, 514 transmission substations, and connections to the grids of the Atlantic Provinces, Ontario and the US.

Other power suppliers are Independent Power Producers (IPPs) which install and operate generating facilities under a contract with Hydro Quebec Distribution and Hydro-Quebec Production. IPPs respond to Hydro Quebec Distribution calls for tender (or RFPs[232]) that define the conditions under which they will supply energy. Prices paid to IPPs are often higher than the consumer prices of electricity in the province.

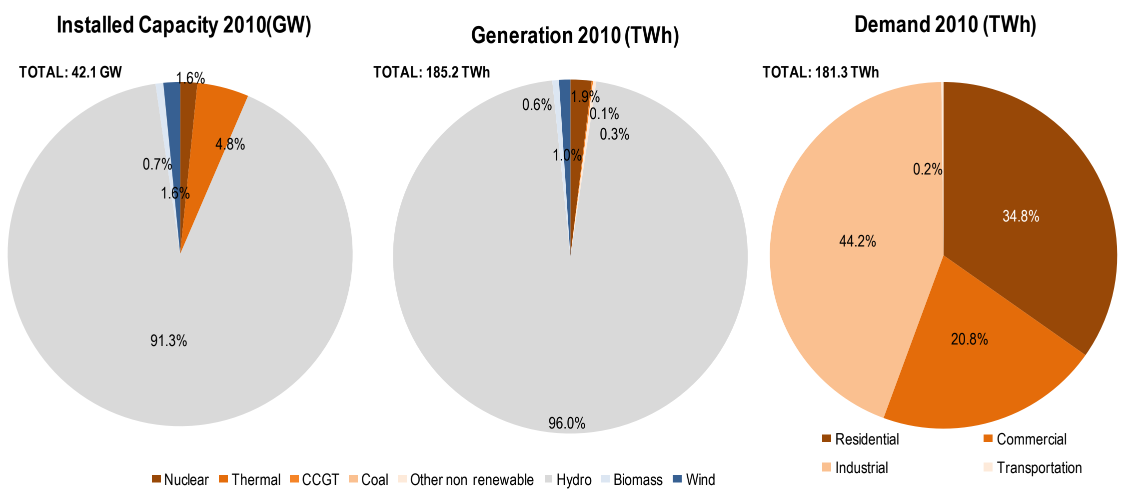


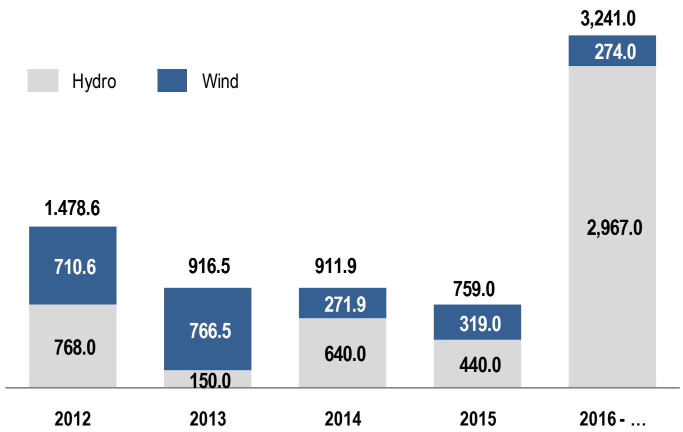
Figure 115. Quebec – Installed capacity (GW), generation (TWh) and demand (TWh) – 2010 [233]

Installed capacity: The main source of power in the province is hydro. In 2010 91% of the total installed capacity (42 GW) in Quebec consisted of hydroelectric plants. 5% of the installed capacity consisted of thermal plants. The only nuclear plant in Quebec, with 675 MW installed capacity, was shut-down on December 28th, 2012. Biomass and on-shore wind plants also contributed to the mix (the latter accounted for 1.6% of installed capacity in 2010).

Generation in Quebec was 185.2 TWh in 2010. 96.0% was produced by hydro power plants, less than 2% came from nuclear power, 1.6% was from renewable sources, and the rest from fossil fuel plants.

Generation projects: Most of the generation projects proposed for the next 4 years in Quebec consist of hydro and wind farms. Beginning in 2012 approximately 7.3 GW of new capacity will be added to the Quebecois system. 5.0 GW should come from new hydro plants, and the remaining 2.3 GW from on-shore wind farms[234].

[232] Over the report the terms call for tender, request for proposal and RFP are used indistinctively to represent solicitation of electricity through a bidding process.
[233] Source: Statistics of Canada,CANSIM: tables 127-0008 and 127-0009, available at: http://www5.statcan.gc.ca/cansim/a33?RT=TABLE&themeID=4012&spMode=tables&lang=eng
[234] Source: Interviews, Prysma analysis



Technology	Cumulative Installed Power (since 2012)
Hydro	4,965.0
Wind	2,342.0
TOTAL	**7,307.0**

Figure 116. Quebec – Proposed generation capacity (MW)[235]

Electricity price formation: There is no electricity pricing on a day-to-day wholesale market in Quebec. Hydro Quebec Distribution is the operator of the system and controls the power market. The company buys a maximum of 165 TWh of heritage electricity from Hydro Quebec Production. Other power producers, Hydro Quebec Production included, are invited to tender the production of additional power at prices set by bilateral contracts.

Incentives to generation: Incentives for renewable technologies consist of RFPs to contract given amounts of power for producers at given prices. For instance, Hydro-Quebec launched RFPs for on-shore wind in 2005, 2008, 2010 and 2012. The most important incentives are summarized in the table below.

TECHNOLOGY	INCENTIVES
ON-SHORE WIND	**RFPs – Calls for tender** **Other** • Green Technology Demonstration Program • Tax Credit for R&D • PAIE • Accelerated Capital Cost Allowance
OFF-SHORE WIND	n.a.
PHOTOVOLTAIC	n.a.
HYDRO POWER	**RFPs – Calls for tender** 236 **Other** • Green Technology Demonstration Program • Tax Credit for R&D • PAIE Accelerated Capital Cost Allowance
CCGT COAL	• Tax Credit for R&D • PAIE • Accelerated Capital Cost Allowances

Figure 117. Quebec – Incentives to electricity generation (example, not comprehensive)

[235] Source: Interviews with federal sources – the characteristics and quantification of projects may vary with the source used and the timing and data collection. For instance HydrQuebec displays slightly different figures in its web page. Confidential. Prysma analysis

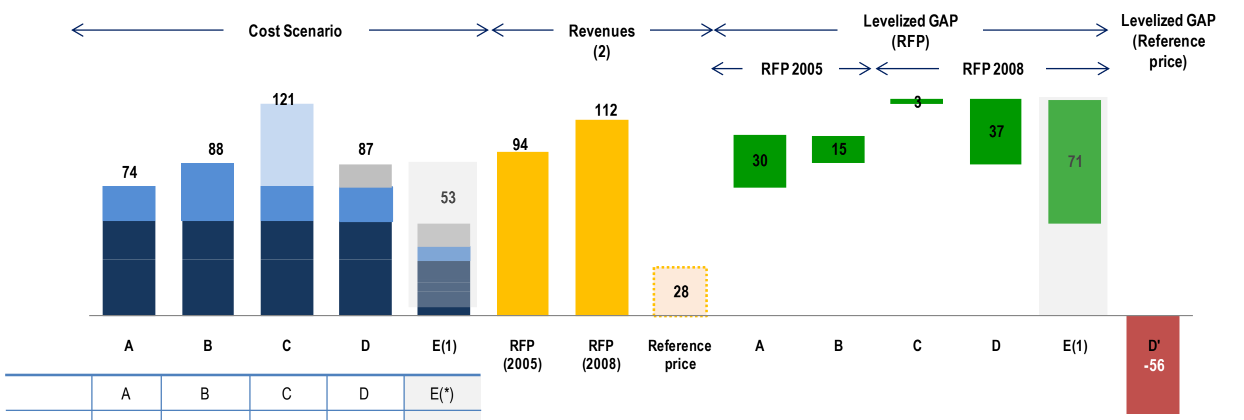
[236] On June 30, 2010, Hydro Quebec approved contracts for a separate RFP for 13 hydro projects totalling 150 MW of small hydro (<50 MW). This RFP resulted in 20-year contracts at a price of 7.5 ¢/kWh, indexed annually at 2.5% for the duration of the contract.

FIRST CALL FOR TENDERS (1,000 MW)	SECOND CALL FOR TENDERS (2,000 MW)
February 2005 – Eight contracts signed	**June 2008 – Fifteen contracts signed**
• Total installed capacity of 990 MW for an annual output of 3.2 TWh • Two suppliers chosen: • Commissioning of eight wind farms between 2006 and 2012 • Average energy price of 6.5 ¢/kWh + 1.3 ¢/kWh transmission cost + 0.5 ¢/kWh balancing cost = 8.3 ¢/kWh • All wind farms will be located in the Gaspésie region of Quebec • Minimum 40% to 60% regional content required for each wind farm	• Total installed capacity of 2,004 MW for an annual output of 6.4 TWh • Eight suppliers chosen: • Commissioning of fifteen wind farms between 2011 and 2015 • Average energy price of 8.7 ¢/kWh + 1.3 ¢/kWh transmission cost + 0.5 ¢/kWh balancing cost = 10.5 ¢/kWh • Projects located in eight regions north and south of the St. Lawrence River • Minimum Gaspésie regional content 30% for wind turbines and minimum Quebec content of 60%

Figure 118. Quebec – Examples of competitive solicitations[237]

6.4.1 Detailed business cases – Quebec / On-shore wind

Simulations result in LCOE of on-shore wind in Quebec in the range of 75-110 US$/MWh. These costs are slightly higher than the costs obtained from simulations of on-shore wind plants in Alberta.



	A	B	C	D	E(*)
Capacity factor	35%	35%	20%	35%	35%
DR	5%	8%	5%	5%	5%
Size-MW	120	120	120	120	140
Transm.	NO	NO	NO	YES	YES

Project operating results

	A	B	C	D	E (*)	D'
NPV (M$)	97	31	-11	122	303	-227
IRR	11%	11%	5%	12%	32%	-

Figure 119. Business cases – On-shore wind in Quebec (2012 US$/MWh)

Without policy support it is very difficult to define a profitable wind generation project in the province. Incentives to on-shore wind consist of RFPs that result in bilateral contracts at agreed prices between electricity producers and Hydro-Quebec Distribution. The first RFP for on-shore wind in Quebec was signed in 2005 at an estimated average price of 83 US$/MWh (94 US$/MWh in 2012US$). The second RFP was signed in 2008 at an estimated

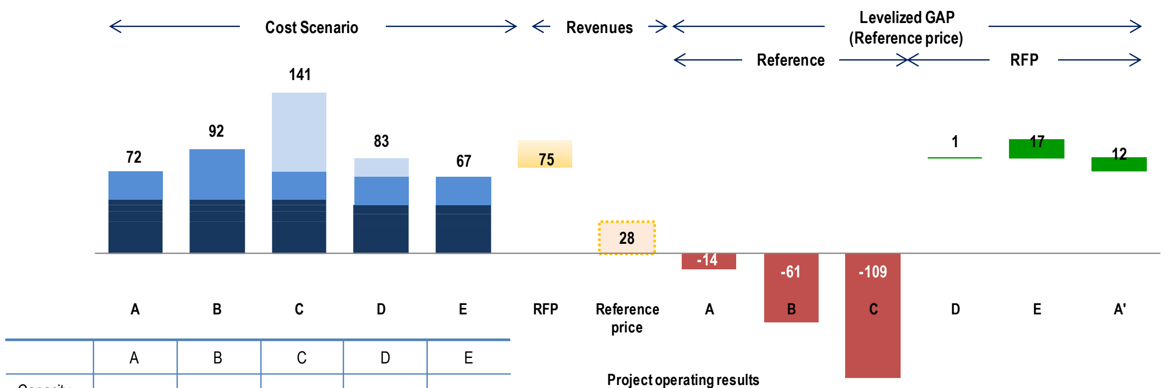
[237] Source: Hydro Québec Distribution – Ensuring Québec electricity supply. www.hydroQuébec.com. The third request for proposal (2010) was for aboriginal and community projects and was restricted to plants with a maximum size of 25 MW.

average price of 105 US$/MWh (112 US$/MWh in 2012US$)[238, 239]. The assertions of some investors, claiming that Hydro-Quebec improved the conditions of the second RFP to better adjust them to higher prevailing generation costs, have not been substantiated by the utility[240].

Both RFPs appear to have provided reasonable business cases to investors that defined projects with good technical and operational characteristics. At the price levels of the first RFP, simulations show that investors may be obtaining positive income during the lifetime of the plant, but that their business cases would be thin. At the price levels awarded in the second RFP, it would appear that investors could attain positive profits and good NPVs over the lifetime of their projects, reaching IRRs in the ranges of 5-15%.

Projects must operate at capacity factors higher than 25% to turn out a profit. This appears to be perfectly feasible, given that average capacity factors for on-shore wind in 2010 in Quebec were ~33%. On-shore wind plants that could reach generation costs similar to those in Alberta would have very attractive returns, as shown in the Case E simulation.

6.4.2 Detailed business cases – Quebec / Hydro



	A	B	C	D	E
Capacity factor	50%	50%	25%	40%	50%
DR	5%	8%	5%	5%	5%
Gross MW	15	15	15	25	25

Project operating results

	A	B	C	D	E	A'
NPV (M$)	-28	-38	-47	-6	14	4
IRR	-	-	-	5%	8%	7%

Impact of technology
Impact of capacity factor
Impact of transmission
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP

Figure 120. Business cases – Hydro in Quebec (2012 US$/MWh)

At the reference price for generation[241], small hydro plants in Quebec would not attain a positive business case. Incentives are necessary to generate interest from investors in this technology. Compensation levels of 70-80 US$/MWh for small hydro appear to provide reasonable business cases to investors in average plants, with LCOEs at 55-80 US$/MWh.

[238] Methodology used to calculate impact of exchange rates: Update 20XX CA$ to 2012CA$ using Canadian inflation and then convert 2012CA$ into 2012US$ using 2012 exchange rate

[239] An RFP (Request for Proposal) of Québec calls for tender by potential suppliers, which become a PPA (Power Purchase Agreement). These terms are interchangeably used in this report.

[240] There have been other RFPs in Quebec. But only the first two have been selected as examples.

[241] The reference price for electricity in Quebec used in simulations was 27.9 US$/MWh

6.4.3 Quebec – Lessons learned

On-shore wind: Any on-shore wind plant in Quebec requires some type of incentive to operate profitably. The low reference prices of electricity in Quebec would not be sufficient to define profitable on-shore wind projects. This situation is unlikely to change in the long term.

The RFPs defined by Hydro Quebec appear to have been successful. First, because RFPs are supporting the development of on-shore wind projects in Quebec. Second, because Hydro Quebec already has the infrastructure, the know-how and the data to reproduce additional RFP, and to define mutually agreeable contracts with on-shore wind electricity providers. Changing something that is working would not be recommendable.

If the Quebecois policy makers desired to significantly increase the on-shore wind capacity in the region, slight modifications to RFPs might trigger additional interest from investors.

- Prices could be adjusted to reflect technical developments and future cost trends of the technology. Costs of on-shore wind generation may drop in the short term – according to sector experts – and this would imply lower reference prices for potential future RFPs. However, the actual levels of cost reduction, and the speed at which they will take place are not clear. It would be critical to use an accurate database of real project costs in the region to ensure that the adjustments are optimal. It is assumed that Hydro Quebec has the relevant information and uses it accordingly.
- Reducing the requirements for local content might contribute to reduce capital costs of on-shore wind plants in the region. However, such an action could also result in a reduction of job creation in Quebec. Priorities of Quebecois policy makers will define whether this possibility ever comes to pass.
- Providing more information about policy objectives, transfer costs, and other quantitative factors of the provincial market may also contribute to increase the interest of investors. For instance, expanding the depth and detail of the data provided by Hydro Quebec. This could reduce the risks of potential participants at no additional costs to Hydro-Quebec, or to the public in Quebec.

6.5 France

Two main actors are responsible for the organization of the French electricity market: the Commission de Regulation de l'Energie and the Ministére de l'Ecologie, du Développement Durable et de l'Energie. The generation sector in France is highly concentrated. 95% of electricity generation comes from three companies: EDF, GDF Suez (mainly Compagnie Nationale du Rhône (CNR)), and E.ON France.

The transmission system is owned and operated by the Reseu de Transport d'Électricité (RTE) – an entity fully owned by EdF. The distribution system is organized in geographical areas, with concessions by the local authorities to a distributor. Électricité Réseau Distribution France (ERDF), a subsidiary of EdF created in 2008, represents 95% of the distribution system in France.

There are two types of suppliers: incumbent suppliers and alternative suppliers. An incumbent supplier offers contracts at regulated prices. Examples of incumbent suppliers are EdF, the local distribution companies (LDCs), and their subsidiaries. Alternative suppliers are those which offer contracts at market prices. On June 30th, 2012, there were about 160 active local suppliers in France, some of them incumbent suppliers, which operate in specific geographic areas[242]. Since July 1st, 2011 alternative suppliers can buy up to 25% (not to exceed 100 TWh) of nuclear electricity production from EdF[243].

Installed capacity in France in 2011 was 126.4 GW. This figure has remained fairly stable in the last years. Almost half of it consists of nuclear power plants (49.9% in 2011). France is the largest country in Europe in terms of nuclear installed capacity, and the second in the world, after the United States. The rest of the installed capacity in 2011 was divided between thermal plants (22.0 %), and renewable sources (28.1%). The bulk of RET consisted of hydro plants (20.1%), wind farms (5.2%), solar farms (1.7%), and plants based on other renewable (1.0%).

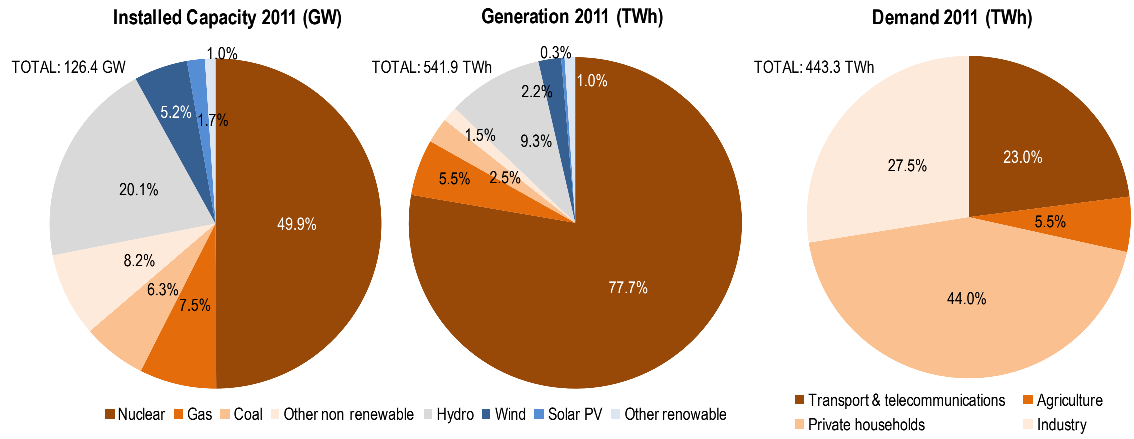


Figure 121. France – Installed capacity (GW), generation (TWh) and demand (TWh) – 2011[244]

Generation: The total power generated in France in 2011 amounted to 541.9 TWh, with the most part coming from nuclear generation (77.7%). Thermal and hydro plants accounted for 9.5% and 9.3% of the total respectively. Renewable generation in France consisted until recently only of hydro. But other renewable energies are significantly increasing and in 2011 accounted for 3.5% of the total generation of the country, mainly provided by on-shore wind plants (2.2%).

France is in the midst of a national debate to re-define the country high level energy policies, and how the electricity mix in the country should evolve in the future. An extensive debate is taking place to define the preferred generation mix and the associated strategic, environmental, economical, and sustainability implications. Two main issues center the debate (1) how to deal with the increase in electricity demand in a sustainable, economic and safe way, and (2) how to simultaneously reduce the environmental impact of energy consumption.

Demand: In 2011, France's demand of electricity amounted to 443.3 TWh (44.0% from private households, 27.5% from the industrial sector, 23% from transport and telecommunications, and 5.5% from the agricultural sectors).

Electricity price formation: An important part of the electricity consumed in France (65% of the national consumption in the third quarter of 2012[245]) is negotiated between producers and distributors through OTC (over the counter) contracts, established either through a broker or directly between suppliers and buyers. Another part

[242] Source: Electricity and gas market observatory Q2 2012. Commission de Régulation de L'énergie (CRE)

[243] Source: Ministre de l'Ecologie, du Développement Durable et de l'Energie; EdF Document de Référence 2011; RTE Web page ; ERDF Distribution web page

[244] Source: Réseau de transport d'électricité, "Bilan électrique 2011". Réseau de transport d'électricité. "Statistiques Production Consommation Echanges 2011 ».

[245] Source: Observatoire des marchés de l´électricité et du gaz – Commission de Régulation de l´Énergie 3rd quarter 2012

of the production is sold directly to customers by integrated utilities. The rest is negotiated in the markets[246]. The official wholesale market is the EPEX Spot France. This market, based in Paris, was founded in 2008 after the merger of the French energy exchange Powernext SA and the German exchange EEX AG. Derivatives and futures are traded at the EEX Power Derivatives market, based in Leipzig[247].

Prices in the wholesale market are defined through the clearing of demand and supply. The reference price in the market is the spot price. This price is determined through hourly auctions. This results in certain volatility in electricity prices, which oscillate with the seasons, and the time of the day.

Incentives to RE-generation: The initial mechanism to stimulate renewable generation consisted of feed-in tariffs (FITs). The incentive system was established by the law nº 2000-108 of February 10th, 2000. The distribution network operator has the obligation to buy the electricity generated by plants based on eligible technologies. Hydro, geothermal, on-shore and off-shore wind, solar PV, and cogeneration plants are supported by this scheme. In addition, off-shore wind and solar PV generation, as well as CSP and CPV generation, may currently be contracted through call for tenders or RFPs organized by the Commission de Régulation de l'Énergie (CRE).

Virtual power plants (VPPs) constitute an additional form of stimulus to generation. EdF offers access to a maximum of 5,400 MW of generation capacity to producers, suppliers and traders active in the French market. This capacity is sold in quarterly auctions with specified energy and capacity prices[248].

The next table summarizes some of the most important incentives to generation in the French market:

TECHNOLOGY	INCENTIVES
ON-SHORE WIND	**Feed-In-Tariff** (15 years) • 8.2 €¢/kWh (base year 2007) (10.66 US$¢/kWh) for the first 10 years; 2.8–8.2 c€/kWh (3.64 – 10.66 US$¢/kWh) for the following 5 years (depending on the annual capacity factor of the site). • It is necessary to calculate an <u>initial tariff</u> with a factor "K" which depends on the commissioning date. It is indexed to the ICHTTS and PPE and multiplied by a coefficient. • <u>Annual escalation factor:</u> indexed to inflation through ICHTTS (40%) and PPEI (20%), but only a 60%. **Other:** Research tax credit (30%).
OFF-SHORE WIND[249]	**Feed-In-Tariff** (20 years) • 13 €¢/kWh (base year 2007) (16.9 US$¢/kWh) for the first 10 years; 3-13 €¢/kWh (3.9 – 16.9 US$¢/kWh) for the following 10 years *(depending on the annual capacity factor of the site).* • It is necessary to calculate an <u>initial tariff</u> with a factor "K" which depends on the commissioning date. It is indexed to the ICHTTS and PPE and multiplied by a coefficient. • <u>Annual escalation factor:</u> indexed to inflation through ICHTTS (40%) and PPEI (20%), but only a 60%. **Call for tender** **Other:** Research tax credit (30%).

[246] Source: http://www.cre.fr/marches/marche-de-gros/marche-de-l-electricite

[247] Source: Commission de régulation de l'énergie

[248] Source: MEEDDM – Les tariffs d'achat ; EdF – auction results

[249] The applicable tariff is determined by the date in which the purchase contract application is completed. The application is considered complete when it contains a copy of the receipt referred to in Article R. 423-3 of the Town Planning Code and the elements defined in Article 2 of this Order, with the exception of point 3.

- If the full application of the purchase contract was completed in 2006, tariffs are those of the schedule.
- For applications for purchase completed in 2007, tariffs are those of the schedule indexed by applying the coefficient K.
- For applications for purchase contract completed after December 31, 2007, the applicable FIT rates are those of the schedule indexed on 1 January of the year of application corrected by the coefficient $(0.98)^n$ x K. Where K is defined

TECHNOLOGY	INCENTIVES
PHOTOVOLTAIC	**Feed-In-Tariff** (20 years) Rate applicable to all type of installations (0-12 MW) whose connection request was sent between October 1 and December 31, 2013 and for the following 20 years • 8.40 c€/kWh (10.92 US$¢/kWh) *(subject to adjustments on a constant basis – reviewed by government)*[250] **Call for tender** for projects above 100 kW **Other:** Research tax credit (30%).
HYDRO POWER	**Feed-In-Tariff** (20 years) • 6.07 €¢/kWh (7.89 US$¢/kWh) plus additional 0.5–2.5 €¢/kWh (0.65 – 3.25 US$¢/kWh) for small installations, plus additional 0–1.68 €¢/kWh (0 – 2.18 US$¢/kWh) in winter (depending on the regularity of production). • 15 €¢2008/kWh (19.5 US$¢/kWh) marine. • It is necessary to calculate an initial tariff with a factor "K" which depends on the commissioning date. It is indexed to the ICHTTS[251] and PPE[252]. • Annual escalation factor: indexed to inflation through ICHTTS (45%) and PPEI (15%), but only a 60%.
CCGT **COAL**	A variety of different measures of support. For instance R&D grants, loans, etc.

Figure 122. France – Incentives to electricity generation (example, not comprehensive)[253]

Additional information on tax schemes can be found in Figure 101.

6.5.1 Detailed business cases – France / On-shore wind

The costs of on-shore wind generation in France appear to be gradually decreasing, as it is also the case in other countries in scope (see Section 5.1). But the costs of most new plants and projects are still higher than the reference market prices of electricity in this country (64-75 US$/MWh). It is unclear when the costs of on-shore wind generation may reach a level that makes them competitive at market prices. Therefore, in the short term new on-shore wind plants will still need incentives to present attractive business cases to investors.

Simulations of new on-shore plants in France yield generation costs in the range of 70-100 US$/MWh. This range includes plants that operate at medium to high capacity factors (30-35%), benefiting from low to medium discount rates (4-5%), and with average capital costs (1700-1900 US$/MW). The costs obtained are below the initial FIT level (107 US$/MWh in 2012) provided by the French support scheme for on-shore wind generation (2010). Plants with operation conditions which position them in the low ranges of cost (50-100 MW, 30-35% capacity factor and 5-8% discount rate) might be able to break-even at market prices of electricity (Case A in Figure 123 presents 8% IRR and NPV>0). But the actual business case strongly depends on the operating conditions of the plant.

by the formula indicated below and n is the number of years after 2007 (n = 1 to 2008). The applicable tariff of the contract is indexed annually on the 1st of November, by applying the coefficient L, defined below:

K = 0.5 x ICHTTS1/ICHTTS1o + 0.5 x PPEI/PPEIo;

L=0.4 x ICHTTS1/ICHTTS1o + 0.2 x PPEI/PPEIo, in which formula:

– ICHTTS1 is the final value of the last known value on January 1 of the year of application of the index of hourly labor costs (all employees) in the mechanical and electrical industries;
– PPEI is the final value of the last known value on January 1 of the year of application of the index of producer prices of industrial and business services for the entire industry (French market);
– ICHTTS1o, PPEIo and final values are the last known values at 26 July 2006.

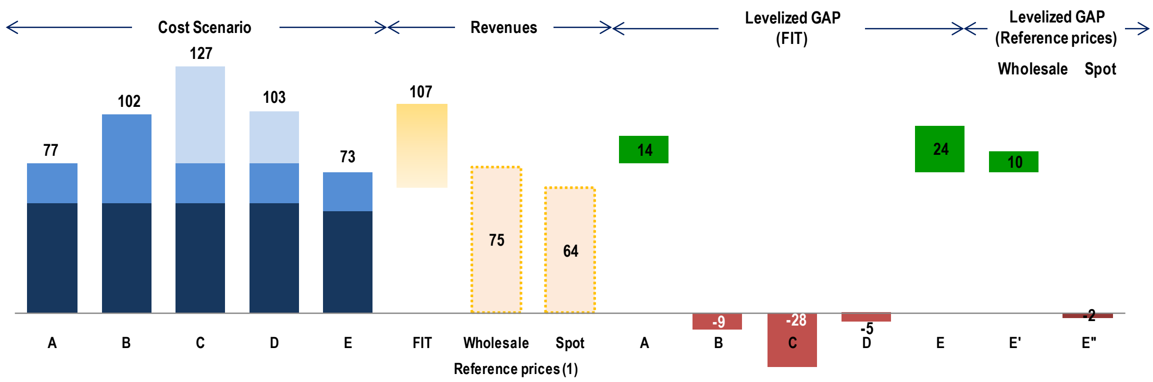
[250] Updated every three months. Last tariff (connection request sent between April 1 and June 31, 2013): 7.96 c€/kWh (10.35 US$¢/kWh)

[251] ICHTTS: Indice mensuel du coût horaire du travail révisé, salaires et charge dans l'industrie mécanique et électrique

[252] PPEI: Indice de prix de production de l'industrie française pour le marché français

[253] MEEDDM, http://www.developpement-durable.gouv.fr/Les-tarifs-d-achat-de-l,12195.html

- Consistently maintaining high capacity factors is critical to attain attractive business cases. Capacity factors must be equal to or higher than 25% to ensure long term profitable operations.
- Highly utilized, large plants can bear higher discount rates (5-8%). Small plants can operate profitably only if they benefit from very low financing rates (3-4%).



	A	B	C	D	E
Capacity factor	35%	35%	20%	25%	30%
DR	5%	10%	5%	5%	5%
Size-MW	50	50	50	50	100

Project operating results

	A	B	C	D	E	E'	E"
NPV (M$)	15	-15	-32	-13	51	15	-19
IRR	8%	8%	1%	4%	10%	7%	5%

Impact of technology | Impact of capacity factor | Revenues | Positive Levelized GAP | Negative Levelized GAP
Cost of fuel | Impact of DR | **Direct impact of policies**

(1) Reference Wholesale price 2011. Reference Spot price 2011

Figure 123. Business cases – On-shore wind in France (2012 US$/MWh)

In addition, the compensation levels of plants eligible to receive the FIT may be subject to a natural degression over the life of the plants, because only a part of the value of the FIT is corrected by inflation-related factors. Simulations using different inflation values have resulted in significant reductions of the real FIT value (in constant 2012 US$). A plant receiving 107 US$/MWh in 2012, could end up receiving 74 US$/MWh in 2027 at current US$, equivalent to 64 US$/MWh in 2012 US$ (using an annual 1% inflation rate).

This FIT scheme favors plants able to attain gradual reductions of generation costs during their operating lives. However, a large part of the costs of an on-shore wind plant are capital costs. They are more or less fixed once the plant is commissioned. Reductions in O&M costs might be possible over time, but the rate of reduction may not be as high in many plants as the one required by the FIT degression formulas.

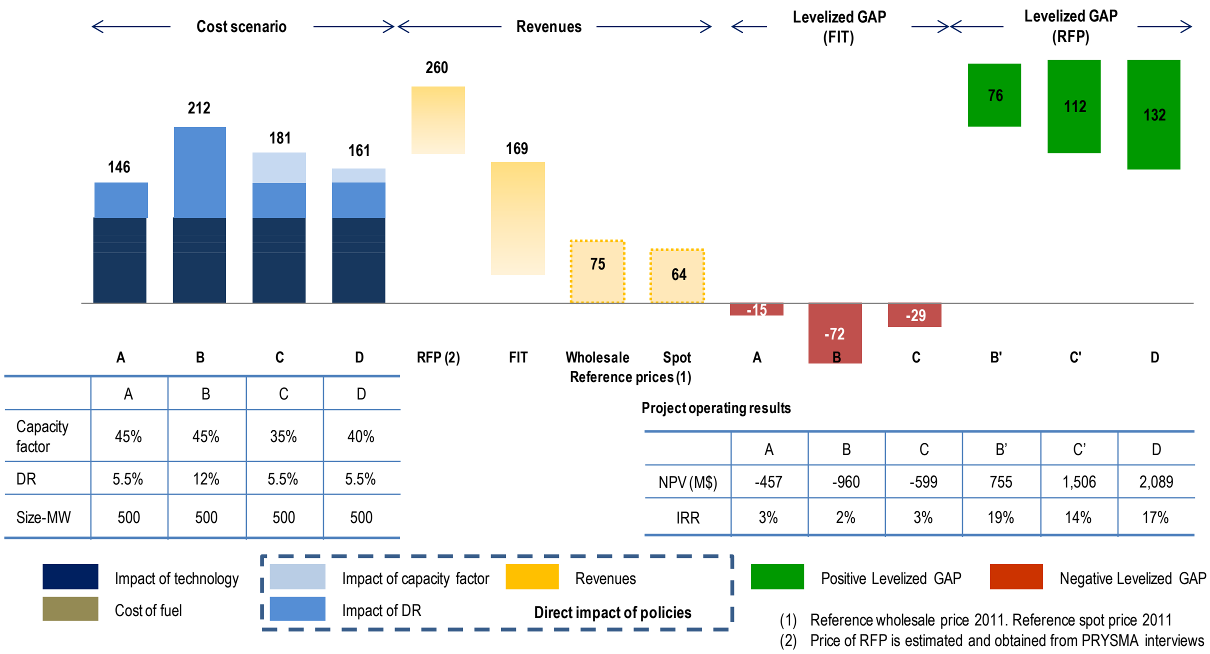
As a consequence, the current FIT scheme defined for on-shore wind in France appears to provide sufficient revenues to plants with low capital costs, operating in conditions which position them in the low ranges of cost, and able to gradually reduce their costs of operation. In contrast, average plants (20-30 MW, 20-25% capacity factor and 5-10% discount rate) would not present advantageous business cases to investors.

6.5.2 Detailed business cases – France / Off-shore wind

Two support systems for off-shore wind exist in France: a feed-in tariff (FIT) and an RFP system based on auctions organized by the French Administration.

Simulations of off-shore wind projects in France yield costs of generation of 140-215 US$/MWh. Significant uncertainty exists about these figures, since at the moment there is only information about projects, not about operating plants. Experience shows that data on generation costs may significantly change from project to operation in this innovative and not yet fully mature technology.

The FIT-based scheme does not appear to provide enough incentive to investors. The initial FIT for off-shore wind in France is 169 US$/MWh (US$ 2012). The FIT levels are adapted by the commissioning date of the plant and by a degression formula composed by two variables partially linked to ICHTTS[254] and PPEI[255]. This may result in a natural degression of payments, as it is the case with the FIT for on-shore wind. Simulations of average conditions result in FIT levels that might even drop below market levels during the life of the plant. In addition, the FIT scheme does not include pre-engagement to the grid. The poor potential returns, and the high levels of risk associated to this particular scheme may have contributed to the low interest of investors[256].



	A	B	C	D
Capacity factor	45%	45%	35%	40%
DR	5.5%	12%	5.5%	5.5%
Size-MW	500	500	500	500

	A	B	C	B'	C'	D
NPV (M$)	-457	-960	-599	755	1,506	2,089
IRR	3%	2%	3%	19%	14%	17%

Figure 124. Business cases – Off-shore wind in France (2012 US$/MWh)

The alternative scheme, based on RFPs appears to have generated much more interest in developers and investors. There have not been official releases of the prices that will be paid for the electricity generated by the plants that will operate under the RFP scheme. Industry estimates assume 200-260 US$/MWh[257] (although the lower range may not be realistic). An additional favorable factor of the French RFPs is the engagement on ensuring connection to the grid. These conditions may also contribute to reductions of the applicable financing rates. As a consequence, industry sources claim that an off-shore wind project could attain a DR of 5-6%, lower than the discount rates that might be attained by a similar project in Germany[258].

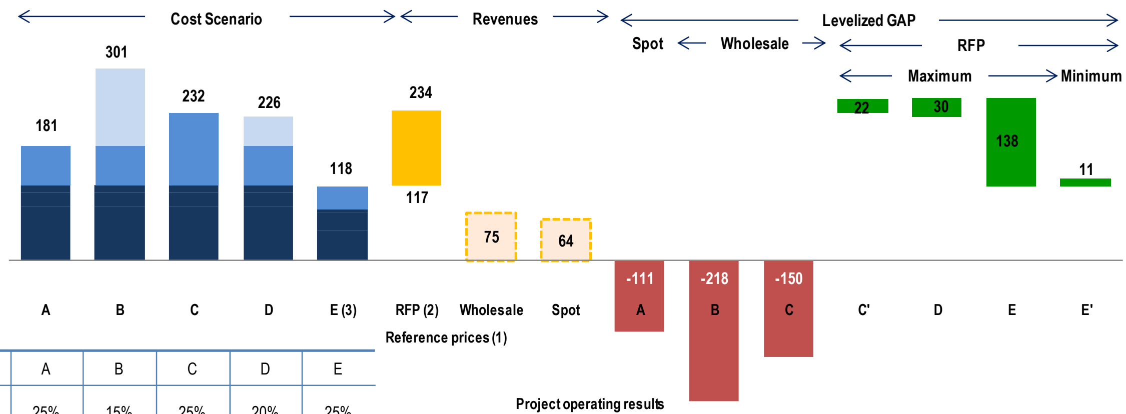
Simulations of the business cases of off-shore wind projects in France show that RFPs may provide investors with high enough profitability to generate interest and commitment, but not windfall profits. RFP projects with 40-45% , 5-6% discount rates and 400-500 MW show positive NPVs and IRRs >10%. The highest estimates of price could yield IRR before taxes of 17%. This would be enough to account for project and operational uncertainty, and to support rates of financing ~5%, and capital returns ~10-12%.

[254] ICHTTS: Indice mensuel du coût horaire du travail révisé, salaires et charges dans l'Industrie mécanique et électrique
[255] PPEI: Indice de prix de production de l'industrie française pour le marché français
[256] At the closing time of this report (2013Q1) no off-shore wind project had been built in France under the FIT scheme
[257] Source: France Energie Eolienne – Le tariff d'obligation d'achat modified with results of interviews and Prysma analysis.
[258] Source: interview with investors.

6.5.3 Detailed business cases – France / Solar PV

Estimated average costs of new solar PV in France are in the range of 150-300 US$/MWh. These costs of generation are higher than the reference prices of electricity in France (65-75 US$/MWh).

However, some developers claim to be able to attain significantly lower generation costs (100-120 US$/MWh). At these very low costs, solar PV plants could be approaching the reference market prices of electricity in France. Therefore, some plants might be able in the future to turn a profit with very low incentive levels. This is excellent news for the sector, but it is not clear when exactly the announced cost reductions will materialize.



	A	B	C	D	E
Capacity factor	25%	15%	25%	20%	25%
DR	6%	6%	10%	6%	6%
Size MW	25	25	25	25	25

Project operating results

	A	B	C	C'(max)	D'	E	E'
NPV (M$)	-63	-73	-61	3	6	54	2
IRR	-	-	-	12%	8%	21%	7%

Impact of technology
Cost of fuel
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP

(1) Reference wholesale price 2011. Reference spot price 2011
(2) Price of RFP is estimated and obtained from PRYSMA interviews. The price also depends on the technology
(3) New developers

Figure 125. Business cases – Solar PV in France (2012 US$/MWh)

In the meantime, most solar PV plants and projects in France still require some kind of incentive to provide positive returns to investors. There is a low FIT for utility-scale solar PV plants in France, but it appears not to be sufficient to interest many investors. However, the new RFPs for solar PV provide an alternative to the FIT scheme. Simulations show that RFPs may provide sufficient revenues to generate investors' interest (prices of RFPs could be in the ranges of 117-240 US$/MWh[259]). With compensation at these levels, best-in-class, utility-scale solar PV plants operating at capacity factors equal to or higher than 20% would attain positive NPVs, and 10-15% IRR. This revenue-cost gap appears to be enough to compensate investors, but not to result in windfall profits.

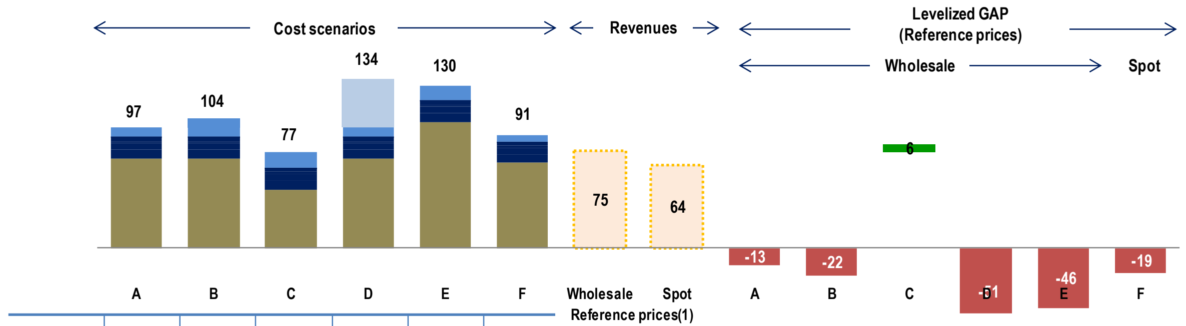
Fine-tuning the technology and operational characteristics of the plants significantly influences the results from simulations: Lower RFP prices could provide positive business cases to plants with very low financing rates (DR <6%). Doubling plant size may lower solar PV generation costs by 15-20%. Maintaining high capacity factors is critical to maximize profitability. It is therefore important that French policy makers keep abreast of changes in the business case of solar PV generation, in order to continue optimizing the conditions of potential future RFPs.

[259] Source: Estimates from interviews with industry actors. Prices that will be paid are not public.

6.5.4 Detailed business cases – France / CCGT

At the present, low capacity factors and slightly higher capital costs of new gas-fired plants, result in poor business cases for this technology in France.

Gas-fired plants have experienced a bubble in capital costs in the last three years due to an array of technology, market and supply chain factors. The capital costs of the CCGT plants included in the database are in the range of 800-1000 US$/MW. In addition, many gas-fired plants in France may be experiencing low capacity factors (30-40%), resulting in significantly higher generation costs.



	A	B	C	D	E	F
Capacity factor	75%	75%	75%	30%	75%	75%
DR	8.5%	13%	8.5%	8.5%	8.5%	5%
SIze MW	400	400	400	400	400	600
Fuel Cost	Avg.	Avg.	-30%	Avg.	+50%	Avg.

Project operating results

	A	B	C	D	E	F
NPV (M$)	-339	-360	98	-493	-1,068	-987
IRR	-	-	12%	-	-	-

Impact of technology
Cost of fuel
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP
(1) Reference Wholesale price 2011. Reference Spot price 2011

Figure 126. Business cases – CCGT in France (2012 US$/MWh)

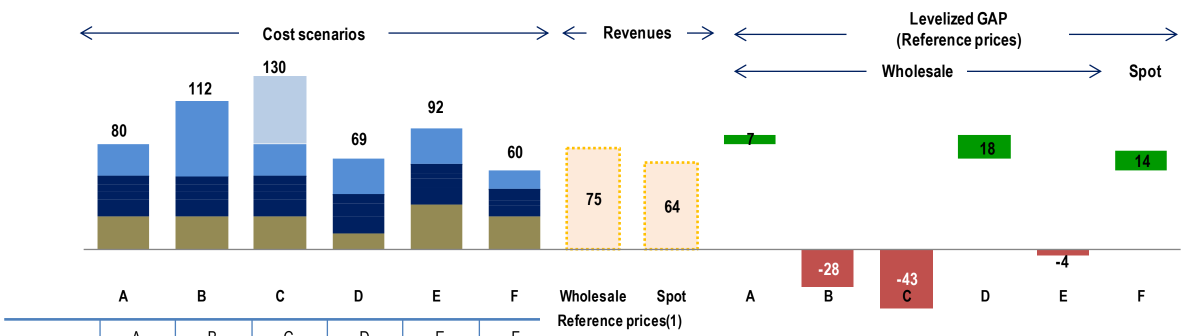
Simulations of new gas-fired plants in France show that none of them would be profitable at the reference spot market price used in the simulations (64 US$/MWh). Higher prices of electricity would be required to ensure positive business cases for the average new gas-fired plant in France; for instance, balancing revenues, or other additional sources of revenue. At the reference wholesale price (75 US$/MWh), best-in-class plants (large and with capacity factors near 75%) would generate positive profits. But their business case would be thin.

Market, technology, and policy developments may reverse this outlook in the near future, returning the average CCGT plant to profitability. Capital costs of gas-fired plants are expected to decrease worldwide, due to rationalization of demand and supply, and to investments in supply chain improvements. Market prices in France may increase if the financial crisis abates, and the past reliance on nuclear generation with low generation costs is somewhat relaxed. Increasing focus on emission costs may make coal-fired plants less attractive vis-à-vis gas-fired plants, therefore increasing the average capacity factors of CCGT plants.

6.5.5 Detailed business cases – France / Coal

Higher generation costs of new coal-fired plants result in poor business cases for this technology in France at the present. Coal-fired plants have also experienced a bubble in capital costs in the last three years due to an array of technology, market and supply chain factors. The plants in the database have capital costs in the range of 1,500-1,700 US$/MW. As it is the case with gas-fired plants, many coal-fired plants in France are currently experiencing low capacity factors (20-30%). This significantly increases their generation costs.

Simulations show that only the largest coal-fired plants would be profitable at the reference spot market price. Higher prices, such as balancing revenues, OTC at higher prices than those of the spot market used in the simulations, or other sources of revenue would be necessary to achieve attractive business cases. At the reference wholesale price, best-in-class plants – large, with high capacity factors (60%) – would generate positive profits.



	A	B	C	D	E	F
Capacity factor	60%	60%	30%	60%	60%	60%
DR	7%	13%	7%	7%	7%	7%
Size MW	400	400	400	400	400	600
Fuel Cost	Avg.	Avg.	Avg.	-50%	+50%	Avg.

Project operating results

	A	B	C	D	E	F
NPV (M$)	43	-413	-576	287	-200	381
IRR	8%	8%	2%	10%	6%	12%

Impact of technology
Cost of fuel
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP
(1) Reference Wholesale price 2011. Reference Spot price 2011

Figure 127. Business cases – Coal-fired in France (2012 US$/MWh)

Market, technology and policy developments may mitigate some of the negative factors that affect coal-fired plants today in France. Capital costs of coal-fired plants are expected to decrease worldwide, due to rationalization of demand and supply, and to investments in supply chain improvements. Market prices in France may increase if the financial crisis abates, and the past reliance on nuclear generation with low generation costs is somewhat relaxed. However, increasing focus on emissions may make coal-fired plants less attractive vis-à-vis other sources of non-renewable generation.

In summary, on average the business case of new coal generation in France today does not appear very promising. Future developments are also uncertain. Therefore, only plants that may ensure streams of revenue higher than the spot market price, and relatively high capacity factors are likely to interest investors.

6.5.6 France – Lessons learned

On-shore wind: The current FIT scheme for on-shore wind appears to provide acceptable rates of return to good to best-in-class plants (50-100 MW, 30-35% capacity factor and 5-8% discount rate); that is, to plants with lower capital costs than the average, which operate at high capacity factors levels, and which are able to gradually reduce O&M costs. However, investors who desire high rates of return, or who are not confident they will reach operation levels which will position them in the low ranges of costs during the 20 years of the lifetime of a plant may find it difficult to commit to on-shore wind projects in France.

Therefore, the current FIT for on-shore wind could perfectly enable the growth and technical development of on-shore wind in France, keeping the sector alive and active. In addition, the FIT levels may result in reduced margins for average plants; this in turn may contribute to stimulate competition and to the emergence of the best in class plants.

If French policy makers decide to significantly increase the pace of development of the on-shore wind sector, this could easily be done by slightly modifying the current FIT scheme. Examples of potential actions would include:

- **Eliminate or reduce the natural degression of the FIT.** Increase the percentage of the FIT which depends on inflation levels to ensure that once a plant enters operation the level of revenues that can be expected is stable.
- **Conduct periodic revisions (at least annual) of the FIT in the future** to adapt it to the actual labor and operating conditions of the plants that receive it. A degression rate that decreases the initial value of the FIT as in Germany is not advisable, because the assumed cost reductions may not accurately reflect the evolution of the technology.

Optimizing the FIT level to provide best-in-class plants with appropriate rates of compensation, and simultaneously preventing windfall profits is not an easy task. Changes in the technical and operational characteristics of the plants under consideration are continuous; the rate of improvement of on-shore wind is not gradual, but cyclical; and plants are different in each country. It is therefore highly recommended that policy makers keep abreast of the technical and operating improvements that affect generation costs of on-shore wind frequently and using local data, not world averages. Only in this way it will be possible to continuously optimize the incentive levels of France[260].

Full elimination of incentives for on-shore wind is strongly discouraged. Simulations show that without some kind of incentives, very few new on-shore plants could profitably operate in France. A decision similar to the one that has been recently made in Spain (declaring a moratorium of incentives to RET generation) would likely freeze the development of the on-shore wind sector in France.

Off-shore wind: The recently launched RFPs for off-shore wind generation in France appear to be successfully enticing developers to invest in this technology. Simulations show that the existing scheme may provide a reasonable rate of return to investors, commensurable with the challenges and risks of the off-shore wind technology in the local operating conditions. The prices (potentially) paid establish a good balance between compensating investors' costs and ensuring that developers do not receive wind-fall profits. Of particular importance is the engagement on ensuring connection to the grid. This factor contributes to decrease the risks of investors, and therefore to reduce their costs, ultimately lowering the price of the electricity generated by this technology.

However, there is not yet enough information available to categorically assert that the current system is optimal. The database of off-shore wind plants is small and the data in it have significant uncertainty. It is necessary to continue enhancing the depth and accuracy of the information related to the projects launched under the RFP scheme to ensure a full understanding of all the factors that may drive the costs of this technology.

It would also be advisable to increase the transparency of the scheme. Ensuring that additional data (for instance the auctions results) are in the public realm could contribute to increase the accuracy of independent analyses. This would provide the French administration with additional knowledge and points of view on which to base their decisions.

[260] Policy makers have used in-depth analyses of the market and technical conditions in France to optimize the algorithms that define the FIT for on-shore wind. However, the speed of technical changes in the sector makes highly recommendable to frequently revise the results obtained with the policy. In order to ensure that high levels objectives are continuously met.

Many databases in the public realm consist of a mix of old and new plants operating in different continents. They do not provide the appropriate level of granularity to make informed decisions about the level of a given incentive in a specific country. It is necessary to develop specific and detailed databases to support the task of policy makers

Large solar PV: The RFP scheme recently established in France appears to be appropriate for a continued development of large solar PV in France, if the compensation levels obtained from interviews are in the ranges of 117-240 US$/MWh[261]. With these data, simulations of new solar PV plants result in reasonable rates of return for investors developing average to best-in-class solar PV plants (15-25 MW, 15-25% capacity factor and 6-8% discount rate).

Significant changes to the current RFP scheme for solar PV in France are not recommendable at this point. But it would be necessary to ensure that the authorization process for solar PV in France is streamlined to reduce delays. This is difficult to do. There are many constituencies involved in authorizations. But a shorter process would certainly contribute to lowering the costs of generation of solar PV by increasing the number of interested investors. Higher numbers of projects would increase competition and potentially lower costs through the selection of the best.

Ensuring that future RFPs respond to the future needs and objectives of French policy makers would require continuous updating of information about all the aspects that define the business case of solar PV generation in France. This could be done through a number of mechanisms:

- Revising the business cases of the plants concurring to the RFPs. More accurate data than those provided in interviews and industry assessment would surely contribute to a better knowledge of the behavior and perspectives of the technology.
- Continuously evaluating the evolving costs of solar PV. This would enable policy makers to identify potential breakthroughs that may significantly affect the future business cases of this technology.
- Increasing the transparency of the scheme. Additional data in the public realm could contribute to increase the accuracy of independent analysis. This will provide the French administration with additional knowledge and information that may be used to optimize future policy decisions.

6.6 Germany

The electricity market in Germany was liberalized by updating the legislation of the Energy Act - "*Gesetz zur Neuregelung des Energiewirtschaftsrechts*" in 1998[262]. The Bundeskartellamt, Börsenaufsichtsbehörde and Bundesnetzagentur are the main regulatory agencies. Four vertically integrated players dominate the German power market: E.ON, RWE, Vattenfall, and EnBW produce over 80% of the electricity generated in the country. Four companies administer the super grid: Amprion, 50Hertz, TenneT TSO, and EnBW Transportnetzte. Around 1.100 distributors guarantee electricity supply to the end customers. Due to the high market concentration in four mayor players, the market is considered by some to be not fully liberalized[263].

Installed capacity: In 2011, Germany's installed capacity reached 167.8 GW. Non-renewable energy represented 61% of the total. The remaining 39% consisted of hydro (7%), wind (17%), and solar PV (15%)[264]. After the Fukushima event, the German government decided to shut down 8 of its 17 nuclear power plants[265].

Generation: Germany's electricity production reached a total of 579.3 TWh in 2011. Coal, accounting for 42% of total production, was the number one generation source in 2011. In the same year, renewable energy production

[261] The compensation levels offered to participants in the recent RFPs for solar PV in France are not public. The levels awarded have been obtained though interviews with actors in the sector.

[262] Source: Library of the Federal Court of Justice (BGH) – BGBII, Nr. 23, S.730.

[263] Source: Monopolkommission – Energie 2011: Wettbewerbsentwicklung mit Licht und Schatten, September 2011.

[264] This figure includes large plants, and smaller (domestic) installations.

[265] Source: World Nuclear Association - http://www.world-nuclear.org/info/inf43.html accessed 11/12/2012.

was 21%, gas-fired plants contributed with 14%. The rest of the generation consisted of nuclear (18%), and of other non renewable sources (5%).

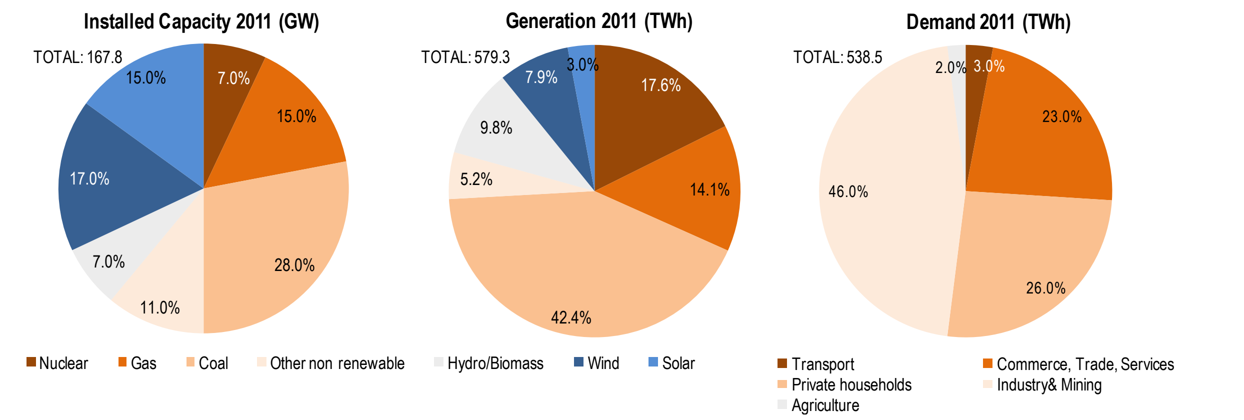
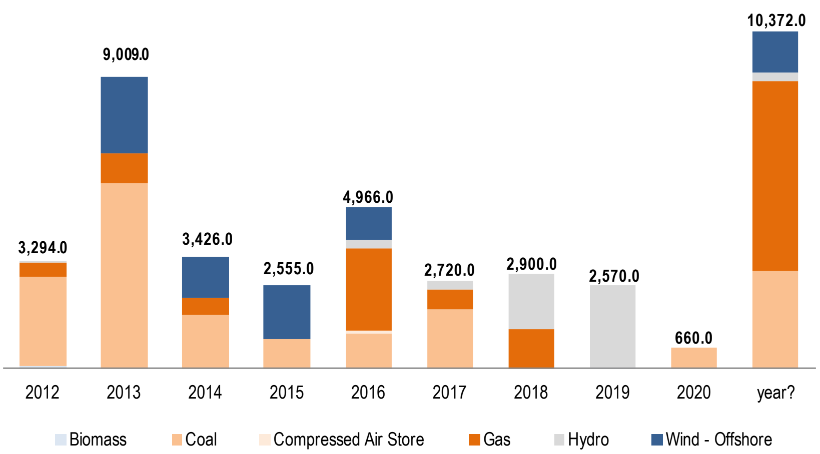


Figure 128. Germany – Installed capacity (GW), generation (TWh) and demand (TWh) – 2011

Demand: The industry and mining sectors – the heaviest electricity consumers – accounted for nearly half (46%) of the power demand on Germany, with 247.7 TWh in 2011; private households, with 140.0TWh (26%), ranked second; followed by commerce, trade and services, which consumed up to 123.9 TWh (23%). The transport and agriculture sectors represented only 5% of the total power consumption in the country[266].



Technology	Capacity (Net MW)	
Biomass	110.0	Specified Projects by BDEW
Coal	17,616.0	
Compressed Air Store	90.0	
Gas	12,024.0	
Hydro	5,113.0	
Wind off-shore	7,519.0	
Wind on-shore	15,900.0	Unspecified Projects**
Solar PV	15,600.0	
Total	73,972.0	

Figure 129. Germany – Proposed capacity projects (MW)[267]

Generation projects: With the fading out of nuclear energy, Germany enacted the Energy System Transformation – “Energiewende”, which defines the objectives for new installed capacity in the EEG Novelle from 2012 on. Figure 129 summarizes the targets by type of technology and year. The goal is to incorporate to the German system a total of ~74 GW of new installed capacity by 2020. The plans show a strong focus on the construction of coal and gas plants, plus the incorporation of additional 31.5 GW of wind and solar PV capacity over the next 9 years.

266 Source: World Energy Council – Energie für Deutschland, 2011

267 Source: World Energy Council – Energie für Deutschland 2012, May 2012, list available from BDEW (Kraftwerksprojekte)

Electricity price formation: There are several mechanisms to trade electricity in Germany: through the power exchange; by directly establishing bilateral contracts; or on broker platforms, through OTC (over the counter) transactions. The bulk of the power traded is through broker platforms (59%) and bilateral contracts (35%)[268]. These contracts are not public. Therefore the prices effectively paid for electricity are not always visible.

Only 6% of the total trade volume is handled in the official trading platform for electricity (EEX – European Energy Exchange). The EEX, based in Leipzig, is the result of the merger in 2002 of the two German power exchanges (Leipzig and Frankfurt). In the EPEX Spot, with base in Paris, electricity from France, Germany, Switzerland and Austria is traded in intraday and day-ahead auctions. The ELIX (the European Electricity Index) is calculated daily on the basis of the aggregated bid/offer curves of all EPEX Spot market areas. Derivatives and futures are handled in the EEX Power Derivatives GmbH separately in Leipzig, Germany[269].

Incentives to generation: In Germany renewable generation is mainly supported through feed-in tariffs paid by the grid operator to the operators of eligible RET plants. The tariffs are set by law and are usually paid over a period of 20 years. The criteria for eligibility and the tariff levels, which vary by technology and output of electricity, are set out in the Renewable Energy Sources Act (EEG) introduced in April 2000. The last revision of the EEG was carried out in 2011 and put in place in January 2012[270].

According to the EEG, operators of renewable energy systems are entitled to payments for the electricity exported to the grid. These costs are passed on to the end-consumer as a surcharge to the regular electricity price. The EEG Novelle from 2012 introduced the so-called market premium and the flexibility premium for system operators who directly sell their electricity from renewable sources in the market.

TECHNOLOGY	INCENTIVES
ON-SHORE WIND	**Feed-in-tariffs** (20 years) • 8.93 €¢/kWh (11.61 US$¢/kWh) as initial tariff payable for first 5 years of operation (initial tariff payment period is extendable according to reference yield[271]); then 4.87 €¢/kWh (6.33 US$¢/kWh) for rest of period. • 0.48 €¢/kWh (0.62 US$¢/kWh) system service bonus increases initial tariff for plants commissioned before 1st January 2015 – bonus payment period is extendable to the same period as initial tariff payment. • 0.5 €¢/kWh (0.65 US$¢/kWh) Repowering bonus (replacement of windmill in operation before 1st January 2002). • Degression starting in 2013 with 1.5% annually. **Market Premium** **Other** • Credits: ❑ KfW Renewable Energy Standard 270, 274 (Erneuerbare Energien - Standard) ❑ Other credits available for projects beyond 25 M€ • Emission trade

[268] Source: Bundesnetzagentur – Monitoringbericht 2011

[269] Source: EEX – official website

[270] In June 2012 took place another revision which introduced new lower tariffs for solar PV installations

[271] According to the Annex 3 of the EEG the reference yield can be calculated on the basis of the P-V curve (power-wind speed curve) measured by an authorized institution at the reference site. The period shall be extended by two month for each 0.75 percent of the reference yield by which the yield of the installation falls short of 150% of the reference yield. (Section 29, (2), EEG) – Calculation: (short fall/0.75)*2 month = xx month of extension for initial tariff payment

TECHNOLOGY	INCENTIVES
OFF-SHORE WIND	**Feed-in-tariffs** (20 years) • 15 €¢/kWh (19.5 US$¢/kWh) initial tariff payable for first 12 years of operation for plants commissioned after 1st January 2018 (initial tariff payment period extendable[272]); then 3.5 €¢/kWh (4.55 US$¢/kWh) for the rest of period. • 19 €¢/kWh (24.7 US$¢/kWh) of initial tariff paid for first 8 years of operation for plants commissioned before 1st January 2018 (initial tariff payment period extendable based on initial tariff payment of 15 €¢/kWh (19.5 US$¢/kWh)); then 3.5 €¢/kWh (4.55 US$¢/kWh) for the rest of period. • Degression starting in 2018 with 7% annually. **Market Premium and Other** • Credits: KfW Off-shore-wind Energy 273 • Emission trade
SOLAR PV	**Feed-In-Tariff** (20 years) – EEG-Novelle 2012 • 12.08 €¢/kWh (15.7 US$¢/kWh)[273] for ground-mounted plants of 1<P<10MW. • Degression (variable) actual 2.5% monthly *(percentage announced on a monthly basis by German government according to yearly capacity installation goal and current status).* • No FIT payment for plant sized above 10MW.
	Market Premium and Other • Credits: ❑ KfW Renewable Energy Standard 270, 274 (Erneuerbare Energien – Standard) ❑ Credits granted by "Länder" government: Hessen/Thuringia (program from Hessian building society), Mecklenburg-Vorpommern (program of state-controlled support institute), Rhineland-Palatinate (support program for energy efficiency from environment ministry), North Rhine-Westphalia (no support for typical constructions on top of single family house), Saarland (Future Energy program) • Emission trading
HYDRO POWER	**Feed-in-tariff** (20 years) • ≤500kW 12.7 €¢/kWh (16.51 US$¢/kWh) • ≤2MW 8.3 €¢/kWh (10.79 US$¢/kWh) • ≤5MW 6.3 €¢/kWh (8.19 US$¢/kWh) • ≤10MW 5.5 €¢/kWh (7.15 US$¢/kWh) • ≤20MW 5.3 €¢/kWh (6.89 US$¢/kWh) • ≤50MW 4.2 €¢/kWh (5.46 US$¢/kWh) • >50MW 3.4 €¢/kWh (4.42 US$¢/kWh) • Degression[274] starting in 2013 with 1% annually. **Market Premium and Other:** Emission trading
CCGT	A variety of tax schemes
COAL	• R&D support for CCS technology • Coal mining incentives: for sales (guarantees), laying in (until 2018), assimilation money for worker

All include REEEP (Renewable Energy & Energy Efficiency Partnership)

Figure 130. Germany – Incentives to electricity generation (example, not comprehensive)

Market premium option[275]: The producers receive the electricity market price + a "market premium payment". The market premium is calculated each month and is equal to the difference between the applicable FIT (decreased by the applicable degression) available for the month, minus a "reference price" calculated monthly.

The reference price consists of two components: the average wholesale market price[276] and the management premium. The management premium depends on the technology and declines over time. It reflects the additional costs that producers face for participating directly in the market e.g. forecasting production, direct marketing of their sales, etc. The premium declines

[272] Extension of initial tariff payment period by 0.5 month for each nautical mile beyond 12 nautical miles that the plant is distanced from shoreline and by 1.7 month for each meter of water depth beyond 20 meters of water depth.

[273] Tariff released for December 2012 (published in November 2012).

[274] Degression is a reduction of the tariffs and bonuses for plants commissioned after the applicable date. Tariffs and bonuses shall be reduced as of the respective date of commissioning and shall apply for the entire period of tariff payment. (source: EEG 1st January 2012)

[275] Source: The German Feed-in tariff: recent policy changes, DB 09/2012; Draft EEG progress report

[276] Calculated as the average of the spot market price of the previous month.

over time as a learning curve is expected. The larger the management premium, the larger the market premium becomes. Sizes of management premiums per technology and year can be found in Figure 131:

Year	On-shore Wind	Off-shore Wind	Solar PV	Other
2012	1.20	0.00	1.20	0.30
2013	1.00	1.00	1.00	0.275
2014	0.85	0.85	0.85	0.25
2015-onwards	0.70	0.70	0.70	0.225

Figure 131. Germany – Initial management premiums EEG (€¢/kWh)[277]

In November 2012, the management premium has been reduced to prevent windfall profits to suppliers of renewable energy, and to reduce the prices the German TSO was paying by these premiums. These were estimated to amount to 2,285,603,086.55 € (including market premium and flexibility premium to biogas).

As of 2013, the ordinance will reduce the management premium for solar, on-shore and off-shore wind power by 0.35 €¢/kWh. The reduction applies to renewable power plants that already market directly as well as plants that decide to market directly in the future. Further reductions will take effect in the following years, so that the premium will amount to:

Year	On-shore Wind/Solar PV	On-shore Wind/Solar PV (Remote controlled)
2012	1.20	1.20
2013	0.65	0.75
2014	0.45	0.60
2015-onwards	0.30	0.50

Figure 132. Germany – New, reduced market premiums (€¢/kWh) – Nov. 2012[278]

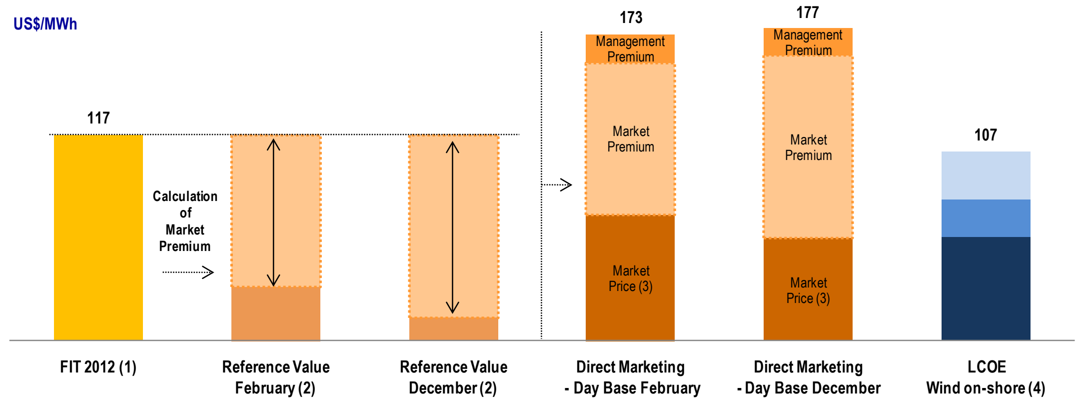
In general, system operators are free to choose between the regular feed-in tariff and the market premium for direct selling[279]. Older renewable installations under the previous (and lower) FIT scheme can profit from the change in form of higher remunerations due to higher FIT payments applicable for the market premium.

Figure 133 shows a simulation of the potential revenues obtained by the same on-shore wind plant when it operates under the FIT or under the market premium scheme. Significant differences exist that may make the premium scheme more interesting for investors in some cases.

[277] Source: The German Feed-in Tariff: Recent Policy Changes, Deutsche Bank Group, DB Climate Change Advisors, September 2012

[278] Source: The German Feed-in Tariff: Recent Policy Changes, Deutsche Bank Group, DB Climate Change Advisors, September 2012

[279] Source: RES-Legal - Germany



Wind On-shore	FIT	Reference Value February	Reference Value December	Market Premium February	Market Premium December	EPEX Spot Day Base Feb. 2012	EPEX Spot Day Base Dec. 2012	Management Premium
Value in US$/MWh	116.09	30.15	12.97	85.94	103.12	71.37	57.95	15.60

Management Premium; FIT 2012; Calculated Market Premium; Reference Value; Average EPEX Spot Market Price February 2012

Impact of technology; Impact of discount rate; Impact of capacity factor

(1) FIT for wind on-shore in February 2012 according to EEG Novelle 2012
(2) Reference Value for wind on-shore February 2012 www.eeg-kwk.net
(3) EPEX Spot Market Price – average median price for February 2012 www.eex.com
(4) See Figure Business case – On-shore wind in Germany (2012/US$/MWh) in scenario D for further assumptions

Figure 133. Example revenue through market premium on-shore wind Feb/Dec (2012 US$/MWh)

Additional information on applicable tax schemes in Germany can be found in Figure 101.

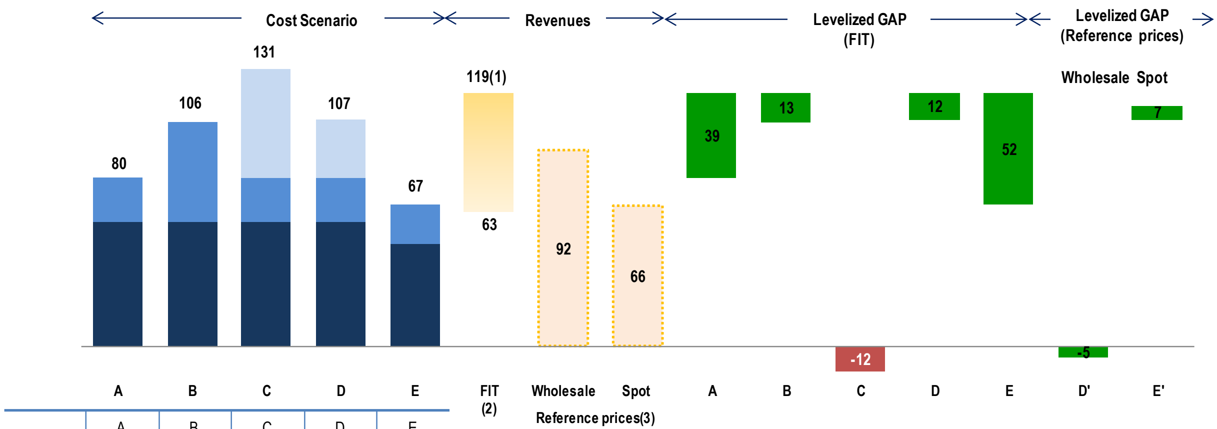
6.6.1 Detailed business cases – Germany / On-shore wind

The costs of on-shore wind generation in Germany (70-100 US$/MWh) appear to be gradually approaching the reference prices of electricity (66-92 US$/MWh). Plants with low capital costs and operational conditions which position them in the low ranges of cost (capital costs lower than 1,700 US$/MW, capacity factors higher than 30%, and financing rates equal or lower than 6%), may manage to generate attractive business cases at the reference prices used in the simulations.

However the picture is very different depending on whether the plant receives the lowest or the highest ranges of potential revenues:

- With the feed-in-tariff, new plants and some older plants can attain positive business cases. Plants with high capacity factors (35%), and low capital costs (1,500-1,600 US$/MW) would attain 40-120 MUS$ NPVs and ~ 10-15% IRRs. Numbers high enough to interest investors.
- Plants with revenues at the higher levels of the reference ranges would attain positive business cases (NPV= 13 MUS$, IRR= 8%).
- At spot or lower market prices (66 US$/MWh), even plants with characteristics which position them in the low ranges of cost would find it difficult to present an attractive business case to investors (NPV <0, low IRR).

In addition, the current scheme results in reductions of the FIT payments over time (degressions). Plants that start operation in the future will receive progressively lower levels of revenue: the initial tariff has a 1.5% degression per year. But plants in operation also see reductions in the revenues received through the FIT scheme, because the FIT level may also be subject to a natural degression[280]. The aggregated impact of these factors may result in important reductions of revenues over time.



	A	B	C	D	E
Capacity factor	35%	35%	20%	25%	35%
DR	5%	10%	5%	5%	5%
Size-MW	50	50	50	50	100

Project operating results

	A	B	C	D	E	D'	E'
NPV (M$)	54	8	-18	6	151	-13	8
IRR	12%	12%	4%	7%	16%	4%	7%

Impact of technology
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP

(1) Initial value for on-shore wind FIT plants commissioned in 2014
(2) FIT is liable to vary through plant life due to operating issues
(3) Reference Wholesale price 2011. Reference Spot price 2011

Figure 134. Business cases – On-shore wind in Germany (2012 US$/MWh)

With the current incentive scheme, average and best-in-class plants that started operation in 2012 can present attractive business cases to investors:

- Plants with average generation costs (70-115 US$/MWh) yield attractive business cases (high IRR, NPV >0, income > 0) when a FIT is provided (119 US$/MWh in 2012).
- Challenged plants (capacity <25%, capital costs >2,000 US$/MW) are unlikely to yield attractive business cases at the current tariff levels in Germany (2012 FIT definition).
- Simulations show that plants with capacity factors >30% and that have a certain size (50-100 MW) present acceptable business cases to the average investor even with current assumed reference prices.

The picture is not so clear for plants that may be commissioned in the future. With the current tariffs, only the best plants, operating at high capacity factors may present interesting returns to investors. Costs of on-shore wind are expected to gradually drop. But there is no agreement on the speed and the size of the cost reductions. Opinions in the industry are quite divided about the potential future developments in on-shore wind generation. Industry actors such as associations and manufacturers announce slight cost increases, or no changes. Policy makers and administrators appear to assume that costs will continue to drop. In addition, the best locations for on-shore wind generation are already taken. Investors may have lesser choice of prime spaces to set up future on-shore wind developments[281].

[280] The term "natural degression" refers to the virtual reduction in compensation (in constant dollars or euro) when the tariff levels are not fully (100%) adapted by inflation.

[281] Repowering is possible but is excluded from the simulations.

An additional cause of uncertainty is the potential evolution of electricity prices in Germany. If future electricity prices are at the same, or at higher levels than today[282], some on-shore wind plants will be able to operate at market prices, without need of premiums or FIT in the short term (2-3 years). However, a drop in market prices higher that 10%, which could be caused by the merit order effect of RE[283], would result in negative business cases: investors would not recover their initial investment.

Investors in on-shore wind in Germany may reap sufficient benefits. But they have to carefully examine each element of their business case to ensure the plants are operating at conditions which position them in the low ranges of cost. In addition, most new on-shore wind plants would still require incentives in the form of tariffs or other types of policy support, to present attractive business cases to investors[284].

6.6.2 Detailed business cases – Germany / Off-shore wind

Technical improvements are contributing to gradually reduce the costs of off-shore wind generation in Germany. However, the actual size and speed at which reductions will take place is not clear. Therefore, the resulting ranges of off-shore wind costs obtained from simulations (155-252 US$/MWh) may be open to discussion.

In addition, the risks associated with this technology may be higher in Germany than in other European countries. Uncertainty over the expenditures associated to ensuring connection to the grid, and about the ability of the TSO to execute them is resulting in operation delays[285], and in higher levels of risk[286].

In any case, the cost of off-shore wind generation is still much higher than the reference prices of electricity in Germany. To close the gap between market prices of electricity and generation costs, investors in this technology require additional revenue sources in the form of incentives to generation, grants, or other provisions.

The current FIT scheme for off-shore wind in Germany considers many variables. Similar to the scheme applicable to on-shore wind, the German FIT system for off-shore wind is based on both technical and operating aspects: year of commissioning, distance from the coast, water depth, etc. Also, the scheme establishes a fixed minimum period of time to receive the high initial tariff, with the maximum period depending on technical and operating aspects of each eligible plant[287]. For off-shore wind plants there is also the possibility of applying an accelerated compensation scheme to compute profits. The consequence is a wide range of potential compensation levels.

In addition, the current FIT scheme anticipates cost improvements in plants entering operation in the future. A plant that starts operation before 2018 will receive a higher FIT than a plant that becomes operational after 2018, due to set degression rate (7%), and to a natural degression of the compensation levels provided by the scheme. This situation has been reflected in Figure 135 as an uncertain range of compensation levels, which at some point during the life of the plant may be at values below current market prices.

[282] Refers to real price increments. Nominal growth higher than inflation

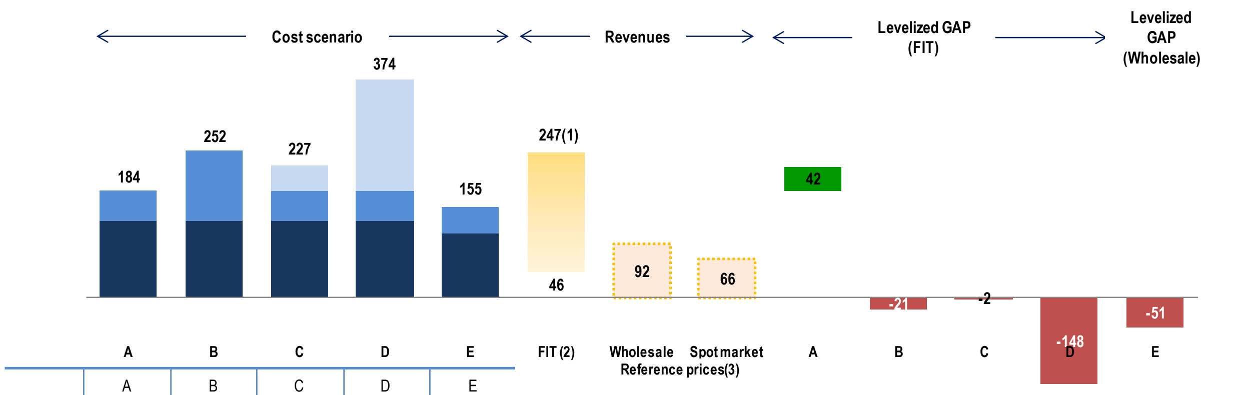
[283] The Merit Order Effect of RE consists in a lower price of electricity in peak times due to the lower marginal cost of renewables.

[284] FIT and spot market prices are always obtainable, but the compensation by repowering or system service bonuses are difficult to obtain and to represent in a long term for investors. They cannot rely only on them.

[285] According to the EEG § 9 the corresponding TSO has the obligation to expand the grid system in order to guarantee the purchase, transmission and distribution of electricity generated from renewable energy sources. In the case of off-shore wind farms, high connection costs contribute to a dispute between plant developers (DONG Energy), TSO TenneT and the German government who is liable for delays in construction as in the case of Borkum Riffgrund 2. (ENERDATA 23/10/2012)

[286] Interviews with investors yielded resulting in slightly higher discount rates for this technology in Germany (6-7%), than for instance in France (5-6%).

[287] The period during which the plant receives the tariff may be extended to reflect side/location characteristics



	A	B	C	D	E
Capacity factor	45%	45%	35%	20%	45%
DR	6%	12%	6%	6%	6%
Size-MW	200	200	200	200	600

Project operating results

	A	B	C	D	E
NPV (M$)	235	-151	-83	-560	-1,305
IRR	10%	10%	6%	-3%	-1%

Figure 135. Business cases – Off-shore wind in Germany (2012 US$/MWh)

As a consequence, it is not clear that the costs of existing and future projects will be covered by the existing FIT scheme. On the one hand, off-shore wind is a technology that has not matured yet; therefore, significant cost reductions may be attainable in the near future. But on the other hand, the value of feasible cost reductions is open to discussion; simulations show that reductions of 15-20% of capital costs in the next five years would be needed to provide future investors with reasonable business cases.

Investors may find it difficult to accurately forecast the business case of generation of a given plant, and as a consequence request additional assurances from the German regulator in order to commit to future off-shore wind projects, and to continue investing in ongoing projects[288].

6.6.3 Detailed business cases – Germany / Large solar PV

In spite of significant reductions in capital costs, the costs of generation for solar PV are still higher than the market prices of electricity in Germany. Even best-in-class plants, operating in very advantageous conditions of capacity factors (20-25%), and capital costs (3,000 US$/MW) show costs much higher than the reference electricity prices in the country (66-153 US$/MWh). As it is the case in the other regions included in this analysis, solar PV plants require incentives or other types of policy-based support to compete against other generation technologies with significantly lower unit costs.

The current tariff existing in Germany is only applicable to plants smaller than 10 MW. The tariff levels have been established at 153 US$/MWh for plants starting operation in January 2013. But the actual tariff level is revised with a degression level published on a quarterly basis for the upcoming three months[289]. With the existing scheme, even a best-in-class plant may find it difficult to break even. Simulations conducted at prevalent capital costs result in negative business cases. At this cost levels, a tariff equal or higher than 170 US$/MWh would be necessary to provide reasonable returns to investors.

[288] DONG Energy put its project Borkum Riffgrund 2 off-shore park in Germany on ice. Enerdata 23/10/2012
[289] The degression factor is said to be set in order to reach the objective in terms of installed capacity for the year.

Nevertheless, as in other countries in the scope, significant cost reductions have been taking place during 2012. Those breakthrough plants operating with the current incentive scheme would result in positive business cases for solar PV in Germany.

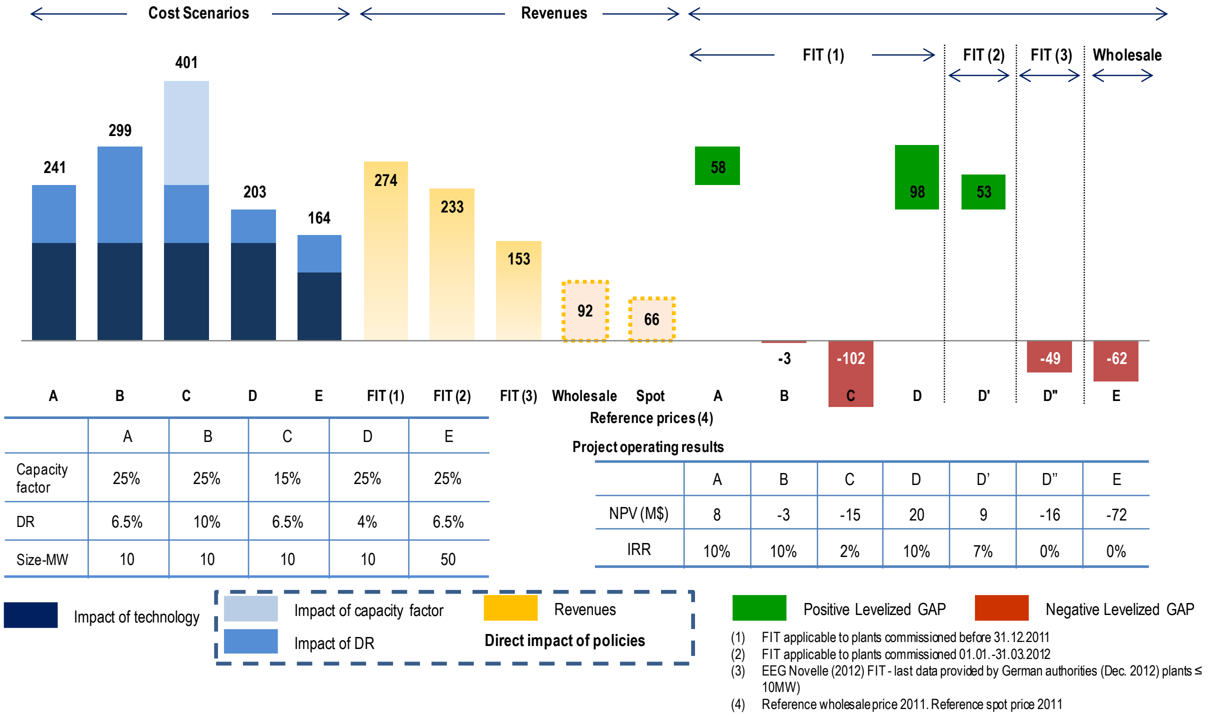


Figure 136. Business cases – Solar PV in Germany (2012 US$/MWh)

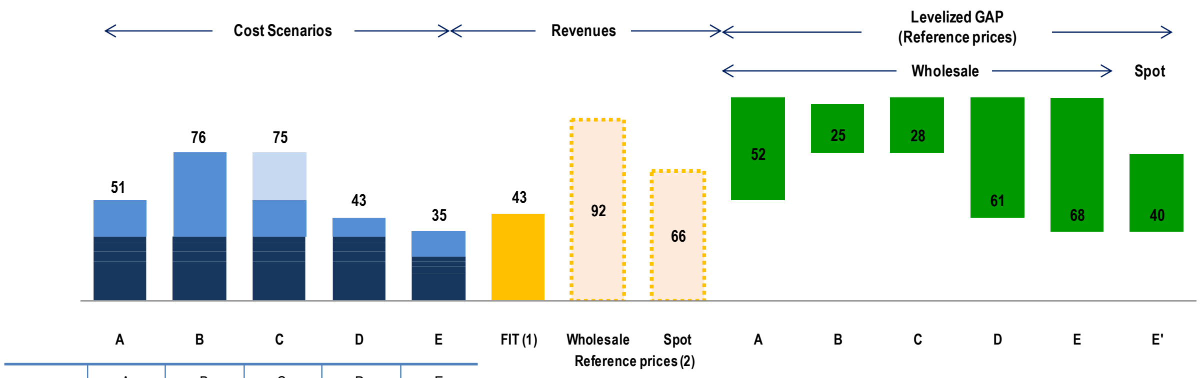
In summary, not breakthrough solar PV plants operating in the grid under average prevailing conditions today are going to find it difficult to generate positive business cases in Germany under the latest revision of the FIT scheme[290].

6.6.4 Detailed business cases – Germany / Hydro

Costs of large hydro plants in Germany are in-line with the market prices of electricity in this country. Large hydro plants (>30 MW), with capacities equal or larger than 40% provide reasonable returns to investors at spot and wholesale market prices[291]. Average capacity factors of hydro plants in Germany have been at 40-45% recently, and at higher levels in the past (see Figure 137)

[290] However if the plant managers opt for the marketing premium scheme, average and best in class large solar PV plants may be able to obtain positive business cases. The premium scheme has not been assessed in depth.

[291] This would favour the establishment of additional large hydro plants, but they have little potential due to nature protection laws and few resources. Some exceptions exist such as the Atdorf plant, a pumped storage/generation hydro plant with size~2,000 MW in development by Schluchseewerk A.G. More interesting from a policy point of view are small and micro plants, but these are as mentioned not attractive for investors.



	A	B	C	D	E
Capacity factor	45%	45%	30%	55%	45%
DR	5%	10%	5%	5%	5%
Size-MW	50	50	50	50	100

Project operating results

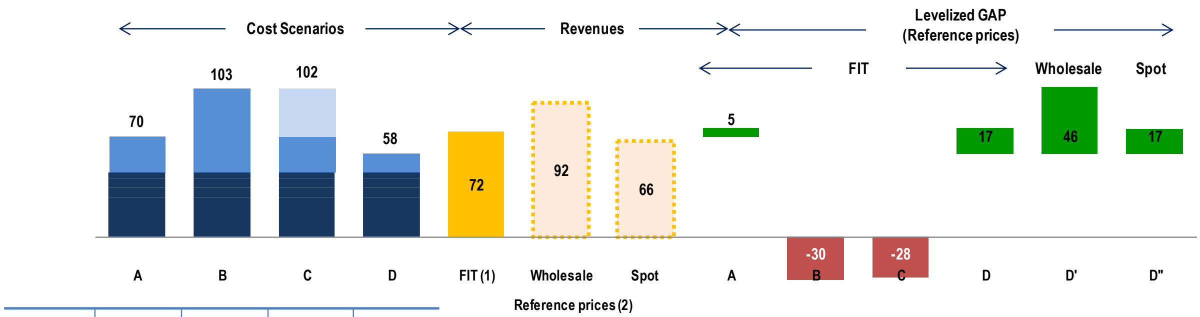
	A	B	C	D	E	E'
NPV (M$)	109	27	32	160	299	167
IRR	14%	14%	9%	18%	22%	15%

Impact of technology
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP

(1) FIT has been designed to support small hydro plants. For medium-large plants its value is lower than market prices (which is this case)
(2) Reference Wholesale price 2011. Reference Spot price 2011

Figure 137. Business cases – Large hydro in Germany (2012 US$/MWh)

As shown in Figure 138 the business case for small hydro plants is rather positive and very sensitive to the size and capacity factor of the plant. Only plants operating over 40% capacity factors appear to be able to achieve positive business cases with current FIT levels[292].



	A	B	C	D
Capacity factor	45%	45%	30%	55%
DR	5%	10%	5%	5%
Size-MW	10	10	10	10

Project operating results

	A	B	C	D	D'	D''
NPV (M$)	0	-10	-11	7	23	6
IRR	6%	6%	2%	8%	13%	8%

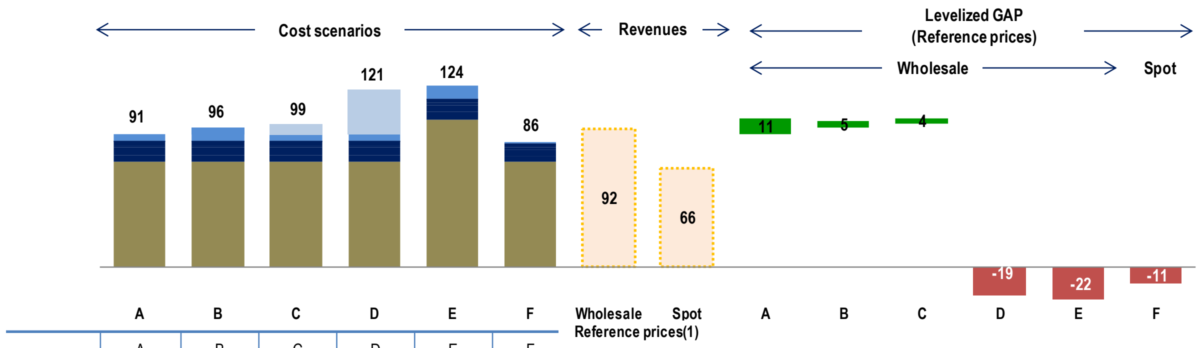
Impact of technology
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP

(1) FIT has been designed to support micro-scale hydro plants. For small-/medium/-large plants its value is lower than market prices (which is this case)
(2) Reference Wholesale price 2011. Reference Spot price 2011

Figure 138. Business cases – Small hydro in Germany (2012 US$/MWh)

292 Refurbishing of existing plants may be a cost effective solution, but the analysis of this possibility is outside the scope of RE-COST

6.6.5 Detailed business cases – Germany / CCGT



	A	B	C	D	E	F
Capacity factor	75%	75%	55%	30%	75%	75%
DR	8.5%	13%	8.5%	8.5%	8.5%	5%
Gross MW	400	400	400	400	400	800
Fuel Cost	Avg.	Avg.	Avg.	Avg.	+50%	Avg.

Project operating results

	A	B	C	D	E	F
NPV (M$)	218	49	35	-194	-511	-754
IRR	16%	16%	11%	2%	-	-

Impact of technology | Cost of fuel | Impact of capacity factor | Impact of DR | Revenues | **Direct impact of policies** | Positive Levelized GAP | Negative Levelized GAP

(1) Reference Wholesale price 2011. Reference Spot price 2011

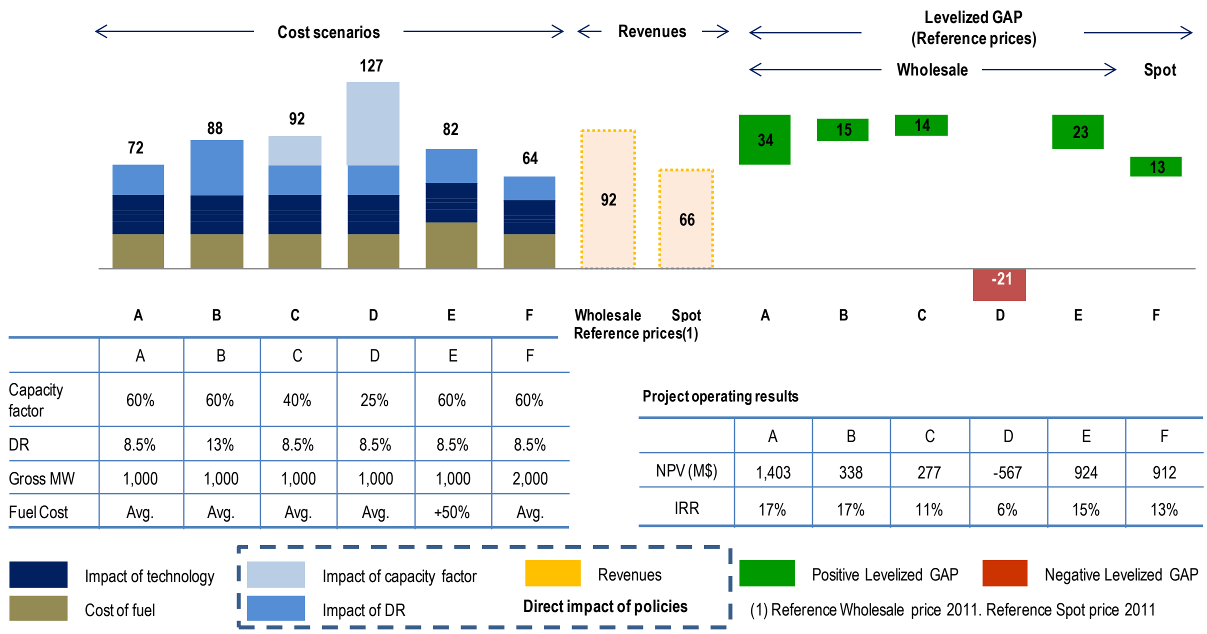
Figure 139. Business cases – CCGT in Germany (2012 US$/MWh)

At the present, average CCGT plants (400-800 MW and 8.5-13% discount rate) may not constitute good investment opportunities in Germany. Currently, many gas-fired plants in Germany are experiencing low capacity factors (30-40 %) that significantly increase generation costs. The same plant operating at a capacity factor of 30% may have generation costs 35% higher than if it operates at 75%. At the current reference prices and average capacity factors, new gas-fired plants in Germany would have difficulties to generate attractive business cases – unless they are quite large (>800 MW), or they benefit from higher than average market prices (balancing or load following premiums).

Market, technology and policy developments may change this in the near future. Capital costs of gas-fired plants are expected to decrease worldwide, due to rationalization of demand and supply and to investments in supply chain improvements. In addition, gas-fired plants are important in the generation mix of Germany because of the flexibility they provide to the system (See Section 5.5). Market prices in Germany may increase if the financial crisis abates and the new generation capacity added to the market is not excessive (commensurable with demand and based on RET at higher prices). The fade-out of nuclear generation may also contribute to higher electricity prices in the future. Increasing focus on emission costs may make gas-fired plants more attractive vis-à-vis coal-fired plants, therefore increasing the average capacity factors of gas vis-à-vis coal.

6.6.6 Detailed business cases – Germany / Coal

Simulations of new coal-fired plants in Germany with technical and operating conditions which position them in the low ranges of cost (1,000-2,000 MW, 50-60% capacity factor and 8-10% discount rate) yield attractive business cases. Size is one of the factors that contribute to this outlook: Germany has very large coal-fired plants. That results in cost reductions due to scale. Sizes of new plants may reach 1,000-2,000 MW. Costs of generation for these large plants range at 60-90 US$/MWh. Simulations of smaller plants (400-800 MW) yield 75-100 US$/MWh.



	A	B	C	D	E	F
Capacity factor	60%	60%	40%	25%	60%	60%
DR	8.5%	13%	8.5%	8.5%	8.5%	8.5%
Gross MW	1,000	1,000	1,000	1,000	1,000	2,000
Fuel Cost	Avg.	Avg.	Avg.	Avg.	+50%	Avg.

Project operating results

	A	B	C	D	E	F
NPV (M$)	1,403	338	277	-567	924	912
IRR	17%	17%	11%	6%	15%	13%

Figure 140. Business cases – Coal in Germany (2012 US$/MWh)

Lower coal prices may be also helping[293], but simulations show that new coal generation would be profitable in Germany for best-in-class plants even if there was a significant increase of coal prices. The business cases are still attractive at coal prices of 3-4 US$/MMBtu (50% increase over standard – or Avg. – prices), for typical discount rates of 8-9%. Low capacity factors and high emission costs[294] would significantly damage the business cases of some coal-fired plants. Facilities with utilization lower than 30-40% are not able to achieve the break-even.

Emission costs are not a significant factor at the current low levels of emission pricing ~4-5US$/Tn.[295]. If emissions costs went back to 10-12US$/Tn. (2012)[296], and exemptions and allowances to coal plants were not applied, the cost of coal generation would increase by 10-15%, significantly tightening the business case of new plants based on this technology.

In addition, other qualitative factors may contribute to improve the outlook of coal in Germany. A high proportion of cost attractive generation from coal plants increases the security of supply in the country. Also, the development of new, cleaner and more effective facilities may help to marginally improve the public image of coal-fired plants, that appears to rather low at the present.

[293] It is contended by some supporters of RET generation that these lower prices may be the result of hidden or indirect subsidies to the coal sector in Germany. Evaluating the actual impact of policy support in the price of coal is impracticable. However, since the business cases of real plants would hold even at higher prices, if incentives are used, their impact over the competitiveness of coal in Germany is comparative low: plants would be built even if coal would had no incentives. Another issue is the impact of indirect support in the P&Ls of plant owners and investors and over the ultimate prices of electricity which may be benefiting from it.

[294] Current emission costs are very low. High emission costs represent only a simulation to gauge the potential impact of this factor.

[295] Source: SendeCO$_2$ as accessed May 2013

[296] Source: Environmental and Energy Study Institute. Fact Sheet: Carbon Pricing around the World

6.6.7 Germany – Lessons learned

On-shore wind: The current German incentive scheme appears to have been defined to allow the addition of new on-shore wind capacity, but at lower rates of growth than in the past. Best in class plants may have attractive rates of return (50-100 MW, 30-35% capacity factor and 5-8% discount rate). However, in the future it may be difficult to find suitable locations for plants, since the number of locations where the most attractive business cases may be generated is decreasing. The best places may already be taken[297].

If the objective of German policy makers is to eventually eliminate price policy support for on-shore wind, the current scheme with degressions that gradually reduce the levels of the tariffs may be fully appropriate.

If German policy makers desire to influence the growth rate of on-shore wind, it could be done by adapting the degression rate of the tariffs to the actual cost reductions experienced by the on-shore wind sector in Germany. This would not significantly modify the current scheme:

- For instance, reducing the potential for a natural degression of the FIT rate for plants already in operation. This could easily be done by ensuring that the FIT level awarded to plants already commissioned is adjusted by inflation. Something similar to what Quebec does.
- Or modifying the rate of degression of the initial FIT for plants commissioned in the future. Experience shows that capital costs of wind have decreased in the last 5-6 years, but the reduction could not be linear, but follow a cyclic pattern. Plants today appear to have lower costs, but future events may delay the rate of cost reduction or even reverse it. A FIT that decreases linearly may not be fully appropriate to ensure a good alignment between the future costs and the compensations of generation. Providing a revised FIT every year, applicable to projects commissioned in the following two years may ensure a better cost-price adjustment[298].

Off-shore wind: Different reasons support the development of off-shore wind in Germany. (1) The lack of land site availability and of many areas with suitable climate conditions configures off-shore wind as a good opportunity to expand the installed renewable capacity in Germany. (2) Good off- wind quality in some areas in Germany results in high capacity factors for off-shore wind. (3) Significant technology development and innovation are improving the efficiency and cost outlook of this technology.

If German policy makers desire to significantly encourage off-shore developments it may be necessary to continue acting over a number of factors that define the business case, and the perception of risks associated to this technology, specifically in Germany.

- In particular, it is essential to ensure that incentives cover the high capital costs of off-shore wind, providing stable conditions to foster this technology. This will indirectly reduce the risk perception of investors, and reduce the costs of off-shore development. Introducing some changes in the current policy scheme, by slightly affecting the FIT levels may be recommendable. This may be done by modifying the initial tariff, which could apply for a longer period (for instance, to the whole lifetime of the plant).
- In addition, a clarification of the financial issues the TSO has to face to facilitate grid access to off-shore wind developments is necessary to provide assurance to investors[299].

[297] Repowering is not considered in the analyses and simulations of new on-shore wind plants

[298] The FIT is already gradually being adjusted by the current scheme (lowered). A cyclical pattern of costs may result in the need to increase the FIT. This may be unfeasible or impractical.

[299] This assessment is already being conducted. The results were not available at the time of publication of this report.

Other mechanisms that significantly modify the current policies for off-shore wind in Germany would not be recommendable. For instance RFPs, a scheme that is being successful in France, may not be appropriate for Germany today.

- Changing the current scheme system to a different one might be cumbersome to explain and administer. Different concurring schemes contribute to administrative complexity. Changes to the scheme may result in an increased perception of risk.
- RFPs allow more control of the projects by the administration. But it is not clear that German policy makers are interested in increasing the degree of oversight and control over the sector. Rather the opposite appears likely.

Solar PV: The current FIT scheme for large solar PV (renewed in 2012) in Germany does not appear to provide enough incentive to investors unless they benefit from technology breakthroughs resulting in significant cost reductions. Or in other words, at the current levels of costs of generation it is difficult for a solar PV plant in Germany to ensure reasonable rates of profitability if the plant is connected to the grid.

If German policy makers desire to continue stimulating the growth of solar PV at the rates of the past it would be necessary to continue providing support to this technology in the short and medium terms through any of the exiting support measures (FIT or market premium).

- Best-in-class, new solar PV plants (10-20 MW, 20-25% capacity factor and 5-8% discount rate) would need a tariff of at least 170 US$/MWh to display attractive business cases to investors.
- Solar PV plants with breakthrough developments that significantly reduce their costs would need a much smaller FIT (100-120 US$/MWh) to turn a profit high enough to interest investors. Providing this small tariff would ensure that only plants that incorporate significant technology developments are built in the future in Germany.
- Another possibility that would not require direct incentives would be to incentivize learning in solar PV to accelerate the rate of implementation of technology breakthroughs. This could be done by promoting R&D projects focusing on increasing plant efficiency and productivity. Providing funding to international project groups to quickly adopt best practices and to leverage experience and knowledge. However, the effectiveness of this measure may be much lower in real terms, than just increasing or managing the FIT level.

If large distributed generation becomes a priority in Germany in the future, solar PV will have a central role. Policies that incentivize solar PV plants as a part of a smart grid would be needed. Examples could include tax relief policies for large industry sized installations, and priority to sell the excess production to the market. This would require significant adaptations of the German grid. The quantification of the demand of such smart grids in Germany is beyond the scope of RE-COST. Studies that include participation of policy makers and industry experts to calibrate and quantify the implications of these developments for public and private sources of finance are likely to contribute to increase interest from investors.

New RET – indirect levers for development: Actions to control and reduce CO_2 and other greenhouse gases affecting emissions would also indirectly affect RET generation. For instance, taking a firm stance against emissions, and tightening the current policies to increase the costs of CO_2 emissions might contribute to reduce the support to coal-fired plants, and increase the comparable attractiveness of new renewable. Examples of potential actions could be:

- Define higher fines or reduce the allowances for emissions of gas and coal plants.
- Encourage R&D in emission capture and control to advance cleaner technologies through grants or similar policies.

- Push for the decommissioning of the oldest and less efficient facilities that are still operating.
- Eliminate coal incentives. Current German coal subsidy programs are designed to end in 2018. These programs have been protecting the indigenous coal industry for decades and providing an independency from world market prices. It may be advisable to switch the funds destined to support mature and established technologies to the development of new renewables. However, this has to be done with the utmost care to prevent unwanted indirect results. Coal is responsible for a large part of generation in Germany (42% in 2011), and provisions that significantly damage the business case of investors in this technology are not recommendable.

6.7 Norway – Sweden

Norway and Sweden are part of the **Nordic electricity market,** which also includes Denmark and Finland. The Nordic market was one of the first to be liberalized in Europe. Cooperation between the Nordic countries started early in the 1960s, with the foundation of Nordel, an advisory body that seeks to optimize electricity generation and transmission. In 1995, the joint Nordic Electricity Market was established by the Louisiana Declaration, issued by the four ministers of energy of the Nordic countries. In 1996, Norway and Sweden integrated their trading markets. Finland and Denmark joined the Nordic Market in 1998 and 2000 respectively. In 2002 NordPool Spot AS – the Nordic Market Trading Exchange – was established[300]. Electricity is traded in the Nordic Market Trading Exchange NordPool in two different markets: the Elspot (day-ahead market) and the Elbas market (intraday market).

Installed capacity in the countries that constitute the Nordic Market was approximately 97 GW in 2011. Hydroelectricity and CHP[301] power plants accounted for nearly 72% of the total installed capacity. Nuclear power plants represented 12 GW, or 12.4% of total capacity. Wind accounted only for 7.8% of the total installed capacity in 2011, but this technology is expected to significantly grow in the next decade and beyond. Electricity production in the Nordic countries in 2011 was 370 TWh. Sweden was the largest producer, followed by Norway and Finland. Denmark was the smallest producer.

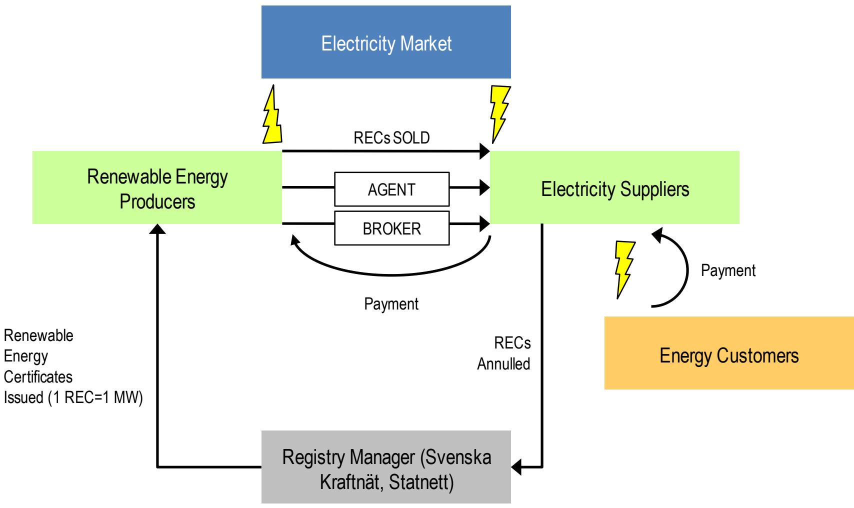


Figure 141. Norway and Sweden – Green certificates[302]

[300] Source: Ea Energy Analyses – The Nordic electricity market and how it can be improved
[301] Source: Main fuels used in CHP are natural gas (main source), biomass, coal, waste, wood and oil.
[302] Source: Graham-Tudor - The Norway-Sweden certificate market in renewable electricity: a model for the European Union? (2012)

In 2003, Sweden introduced the el-certificate system (green certificate market), in the form of a state-created and managed market of certificates between renewable electricity producers and consumers. The stated objective of the scheme was to enhance and increase renewable electricity production, as well as to reach by 2020[303] the target for RET share set in the European Renewable Energy Directive (2009/28/EC).

Green certificates are no longer limited to Sweden, as Norway joined the scheme in January 1st, 2012. The two countries aspire to increase renewable electricity production in 26.4 TWh by 2020. Norway and Sweden mutually share the responsibility for financing new installed RE capacity, with an increase in production of 13.2 TWh each by 2020[304]. The joint Swedish-Norwegian green certificate system is the first example of two nations using the opportunity that the Renewable Energy Directive gives for flexible mechanisms, where Norway can meet its target through investing in RET in Sweden and vice-versa.

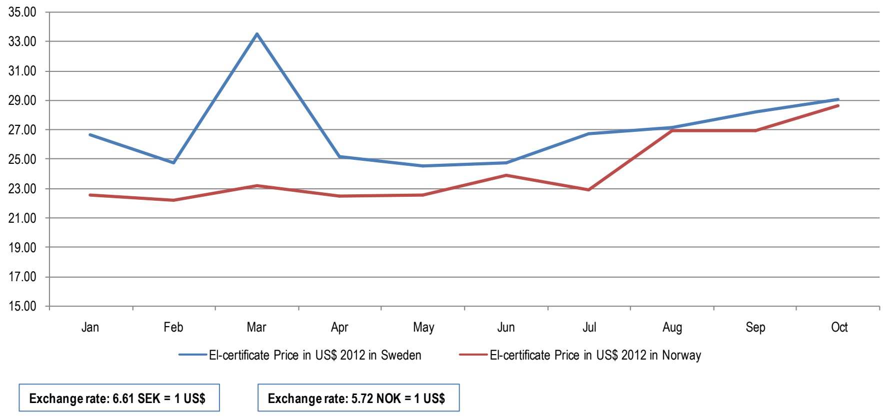


Figure 142. Norway and Sweden – Prices of green certificates (US$/certificate) – 2012[305]

6.7.1 Baseline Norway

Electricity generation in Norway is organized around a liberalized, integrated market, and large state-owned companies which are active in most of the links of the electricity supply chain.

NVE (Norwegian Water Resources and Energy Directorate), established under the Ministry of Petroleum and Energy, is the market regulator in Norway. NVE is responsible for ensuring the development of network regulations, providing market access to power customers, defining straightforward procedures for switching suppliers, ensuring security and quality of supply, and defining efficient regulations for the operation of the Norwegian power system.

The largest electricity producers are Statkraft (Norway's largest and the Nordic region's third largest power producer), E-CO Energi, and Norsk Hydro ASA. 91% of the transmission grid belongs to Statnett SF. The retail market is fully liberalized, with around 98 registered suppliers[306].

The electricity wholesale market in Norway is Nord Pool ASA, which is the official power exchange in the Nordic region. Futures and derivatives are traded in NASDAQ OMX Commodities Europe.

[303] Source: NordPool website

[304] Source: Geoffrey Graham Tudor – The Norway-Sweden Certificate Market in renewable Electricity: A Model For the European Union?

[305] Sources: For Sweden Svenska Kraftnät website: elcertifikat.svk.se, for Norway Statnett website: necs.statnett.no

[306] Source: NVE – Report on regulation and the electricity market 2011

The target for renewable share in 2020 is 67.5%. The climate goal for 2020 is to reduce climate gas emissions by 30%, whereof 2/3 must take place domestically.

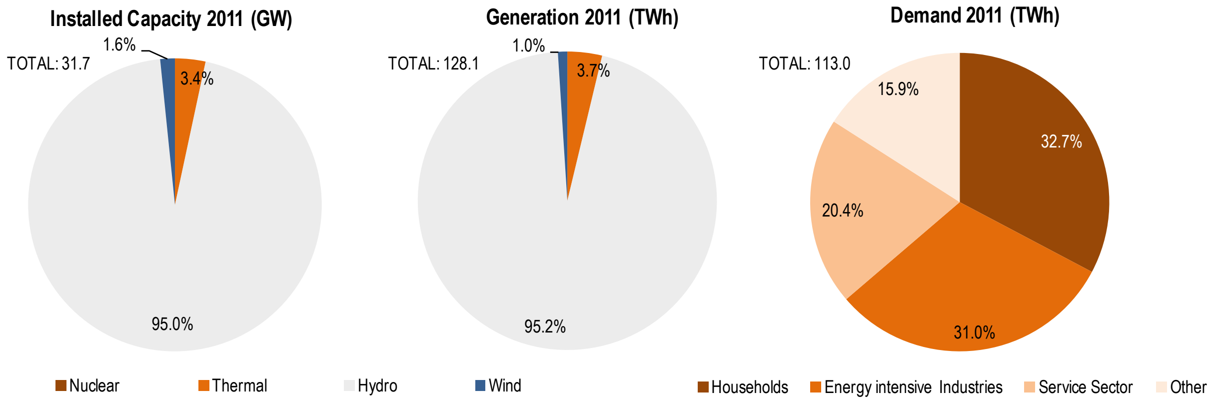


Figure 143. Norway – Installed capacity (GW), generation (TWh) and demand (TWh) – 2011[307]

Installed capacity in Norway in 2011 was 31.7 GW. 95% consisted of hydroelectric plants. The rest included thermal (1062.5 MW) and wind farms (511.5) MW). Norway ranks fifth in Europe in installed renewable energy capacity. The proportion of other generation technologies is very low. There are three CCGT plants in Norway[308] located at industrial facilities: Tjeldbergodden (150 MW), Kårstø (420 MW) and Mongstad (280 MW).

Generation: Norwegian electricity production reached a total of 128.1 TWh in 2011. Hydro traditionally represents 95-99% of total production. Thermal plants are mostly used as back-up for dry years when the water reservoirs are not sufficient to fully cover electricity demand.

Demand: In 2011, the power demand in Norway was 113.0 TWh. More than 60% of the total consumption was shared nearly equally by households (37 TWh) and the energy intensive industry (35 TWh). Consumption dropped during this year to 12% less than the average year, because the climate was mild and wet during the winter months. Therefore, less heating was required by households[309].

Electricity price formation: Norway trades electricity mainly in NordPool. In order to handle bottlenecks in the regional and central grid more effectively, the country grid is split into five different Norwegian Elspot areas. Prices develop differently in each of these areas[310]. In 2011, electricity prices were lower than in the average year as the warm and wet weather had a positive effect on the water reservoir levels.

Incentives: New renewable electricity is supported by the green certificate trade in the common market with Sweden. Although Norway was interested in establishing a joint certificate market since 2004, it did not joint it until 2012. Examples of features that have been optimized over time in the joint agreement include[311]:

- The number of certificates is the same in both countries (13.2 TWh each).

[307] Source: NVE "Annual Report 2011 – The Norwegian Energy regulator", Note that there are slight differences to source in demand due to rounding done in the report.

[308] Source: Statoil website

[309] Source: NVE "Annual Report 2011 – The Norwegian Energy regulator"

[310] Source: NordPool website

[311] Source: www.nortrade.com (31, Aug. 2011), accessed in November 2012.

- The bulk of new renewable energy is expected to come from on-shore wind power (6-7 TWh). The remaining 6-7 TWh could be new hydropower developments, while Sweden's remaining 6-7 TWh may come mainly from biopower.
- Some sectors and plants have received opt-outs from the scheme to prevent damaging the competitiveness of critical sectors of the Norwegian and Swedish economy – including power intensive industries and the forestry sector in Norway, and other electricity intensive industries in Sweden.

Furthermore, there are other programs which support R&D and construction of renewable energy plants.

TECHNOLOGY	INCENTIVES
ON-SHORE WIND	**Green Certificates** for 15 years or maximum until 2035 *(whichever ends first).* **Other** • Tax allowance for R&D costs • Support programs provided by Enova SF, funded by The Energy Fund for environmentally friendly restructuring of energy end-use and energy production • RENERGIX – support for research provided by The Research Council of Norway • Support programs provided by Innovation Norway • Balance depreciation (varies for equipment parts)
OFF-SHORE WIND	**Green Certificates** for 15 years or maximum until 2035 *(whichever ends first)* **Other** • Tax allowance for R&D costs • Support programs provided by Enova SF, funded by The Energy Fund for environmentally friendly restructuring of energy end-use and energy production • RENERGIX – support for research provided by The Research Council of Norway • Support programs provided by Innovation Norway • Balance depreciation (varies for equipment parts)
PHOTOVOLTAIC	**Green Certificates** for 15 years or maximum until 2035 *(whichever ends first).* **Other** • Tax allowance for R&D costs • Support programs provided by Enova SF, funded by The Energy Fund for environmentally friendly restructuring of energy end-use and energy production • RENERGIX – support for research provided by The Research Council of Norway • Support programs provided by Innovation Norway
HYDRO POWER	**Green Certificates** for 15 years or maximum until 2035 *(whichever ends first)*[312] **Other** • Tax allowance for R&D costs • RENERGIX – support for research provided by The Research Council of Norway • Support programs provided by Enova SF, funded by The Energy Fund for environmentally friendly restructuring of energy end-use and energy production • Nordic Investment Bank and Sparebank Vest credit and funding program *(small-scale hydro)* • Linear/Balance depreciation *(varies for equipment parts)*
CCGT	R&D grants
COAL	Not applicable

All technologies also include – REEEP (Renewable Energy & Energy Efficiency Partnership)

Figure 144. Norway – Incentives to electricity generation (example, not comprehensive)

[312] Source: Res-legal: Norway – Overall Summary

Additional information on applicable tax schemes in Norway can be found in Figure 101.

6.7.2 Baseline Sweden

The liberalization of the electricity market started in Sweden in January 1992. The production and sale of electricity were separated from the network operation. Today, the Swedish Energy Agency is the market regulator of the electricity sector. The Swedish national grid is owned by the public utility Svenska Kraftnät. The largest power producers in Sweden, accounting for 85% of the electricity generated in the country, are Vattenfall, E.ON, and Fortum. These largest companies also have a significant share of the retail market (50%)[313]. Electricity in Sweden is traded at Nord Pool ASA, the official power exchange in the Nordic region.

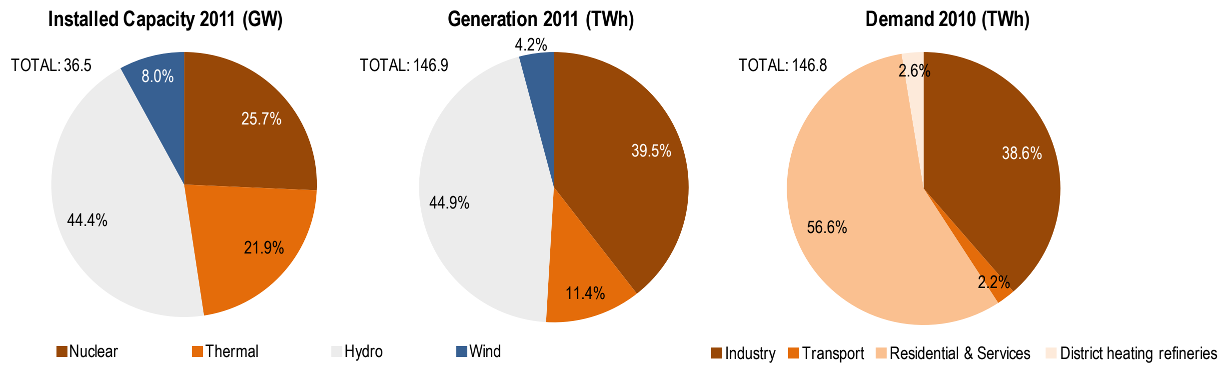


Figure 145. Sweden – Installed capacity (GW), generation (TWh) and demand (TWh)[314] – 2011

Installed capacity: In 2011, Sweden had 36.5 GW of installed power capacity. Sweden ranks number six in installed renewable energy capacity in Europe. The main pillars of Swedish generation capacity are hydro power plants, that accounted for 44.4% of total installed capacity in 2011; and nuclear plants (10 operating nuclear power reactors), with 9.4 GW, equivalent to 25.7% of installed capacity in 2011. Thermal power generated by CHP and biomass[315] amounted to 21.9% of installed capacity.

Generation: Swedish electricity production amounted to a total of 146.9 TWh in 2011, with 44.9% generated by hydro plants and 39.5% by nuclear plants. Thermal generation accounted for 11.4% of the total.

Demand: Two main factors drive electricity demand in Sweden: A relatively large proportion of power intensive industries, and a rather cold climate. In 2010, Sweden consumed a total of 146.8 TWh of electricity. The industrial sector, with 52.4 TWh, accounted for over 38.6% of this amount. The residential and service sectors, with 76.8 TWh, accounted for 56.6%. The remaining power consumption (4.8%) included transportation and distribution, and grid losses.

Generation projects: Sweden plans to reach a 50% share of renewable energy by 2020, with strong focus on the development of wind power. The Swedish Parliament has defined the target of 30 TWh/year in wind production by

[313] Source: Swedeenergy – The electricity year 2011 operations

[314] Source: Swedish Energy Agency and Statistics Sweden

[315] There are two CCGT plants in Sweden that contributes to thermal power energy mix Rya (261-MW, 3+1 CCGT with SGT-800 gas turbines CHP) and Nya Öresundsverket (440-MW, 1+1 CCGT with 9001FB gas turbine CHP)

2030. On-shore wind should contribute 20 TWh/year, and off-shore wind the remaining 10 TWh/year[316]. By 2030, Sweden plans contemplate a fossil fuel free power mix[317].

Electricity price formation: Swedish electricity is traded in the power exchange NordPool. The Swedish electricity market is divided into four bidding areas: from north to south are SE1 (Luleå), SE2 (Sundsvall), SE3 (Stockholm) and SE4 (Malmö). The borders of the bidding areas have been established to optimize electricity transport from the areas where it is produced to the locations where it is consumed[318]. As in Norway, wholesale electricity prices in Sweden during 2011 displayed a downward trend due to favorable climate conditions throughout the year.

Incentives to generation: The main incentive scheme for RET in Sweden is the joint green certificate system with Norway. But there are other measures that reward the construction of sustainable generation projects. Support takes the form of incentives to fund part of the costs of the plants, including additional costs, development costs, and planning costs. Their main focus is wind and biomass technologies[319]. The next table summarizes the most important incentives to stimulate electricity generation in Sweden.

TECHNOLOGY	INCENTIVES
ON-SHORE WIND	**Green Certificates** for 15 years or maximum until 2035 *(whichever ends first).* **Other** • R&D grants • Tax reduction for real estate • Measures to support wind farms in difficult locations • Linear depreciation (varies for equipment parts)
OFF-SHORE WIND	**Green Certificates** for 15 years or maximum until 2035 *(whichever ends first).* **Other** • R&D grants • Energy tax reduction for non-commercial producer/supplier) • Measures to support wind farms in difficult locations • Linear depreciation (varies for equipment parts)
SOLAR PV	**Green Certificates** for 15 years or maximum until 2035 *(whichever ends first).* **Other** • Construction/installation grants
HYDRO POWER	**Green Certificates** for 15 years or maximum until 2035 *(whichever ends first)*. **Other** • Linear depreciation (varies for equipment parts)
CCGT	Several schemes
COAL	

REEEP (Renewable Energy & Energy Efficiency Partnership)

Figure 146. Sweden – Incentives to electricity generation (example, not comprehensive)

Additional information on applicable tax schemes in Sweden can be found in Figure 101.

[316] Source: Sweden Country reports – Energy Efficiency Report

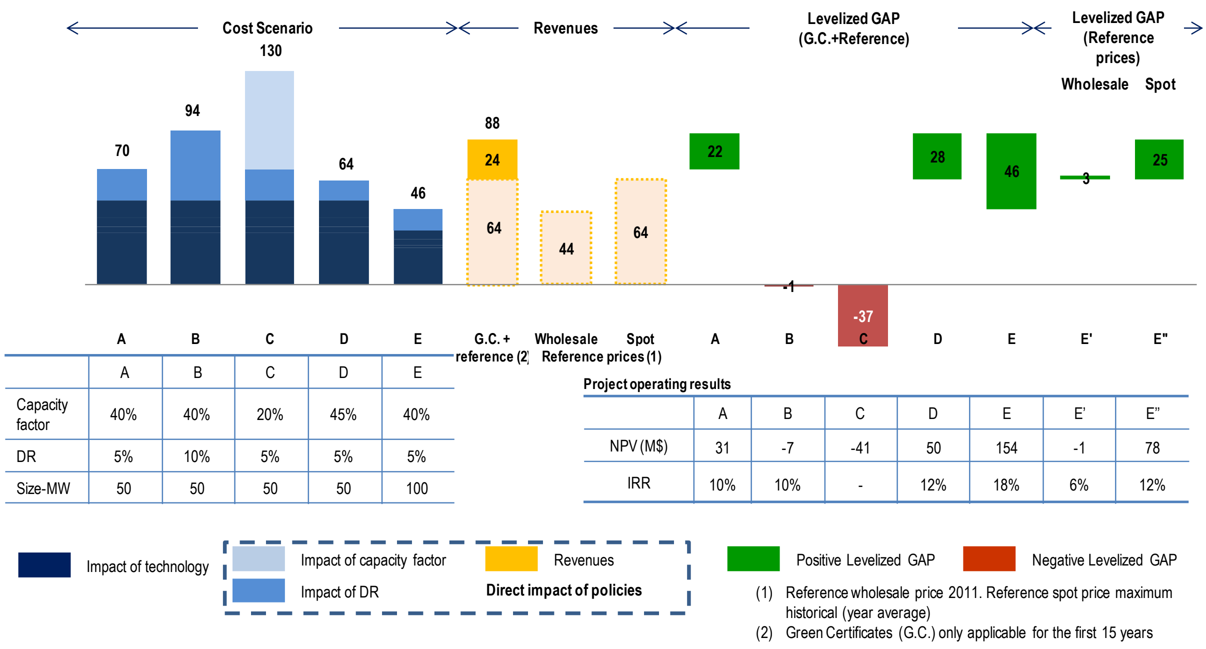
[317] Source: Regeringen „The Swedish energy System“, accessed on 23.07.2012; Sweden Country Report „ Sweden – Energy efficiency report“

[318] Source: Svenska Kraftnät – official website consulted in several occasions between April 2011 and March 2012

[319] Source: RES Legal - Sweden

6.7.3 Detailed business cases – Norway and Sweden / On-shore wind

Simulations of the business cases of on-shore wind in Norway show that, under the green certificate scheme, plants with good technical and operating conditions may deliver interesting returns to investors. Costs of generation of plants with 30-40% capacity factors[320], 5-8.5% discount rate, and 50-100 MW would be at 52-90 US$/MWh. Plants receiving revenues equivalent to market prices of electricity, plus certificates (64-88 US$/MWh) could attain 6-10% IRRs, and NPVs in the ranges 0.39-31.3 MUS$.



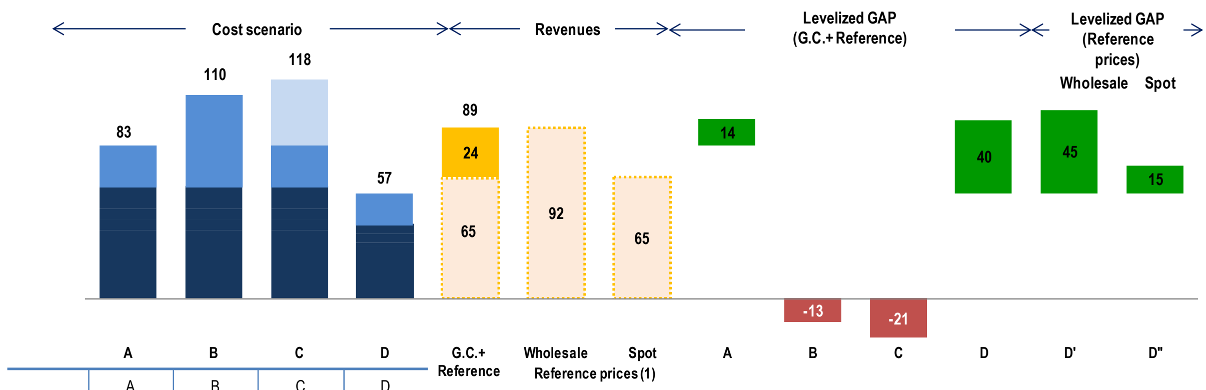
	A	B	C	D	E
Capacity factor	40%	40%	20%	45%	40%
DR	5%	10%	5%	5%	5%
Size-MW	50	50	50	50	100

	A	B	C	D	E	E'	E"
NPV (M$)	31	-7	-41	50	154	-1	78
IRR	10%	10%	-	12%	18%	6%	12%

Figure 147. Business cases – On-shore wind in Norway (2012 US$/MWh)

These results are significantly affected by the characteristics and operating regimes of each plant. A reduction from 40% to 20% in plant capacity factor increases costs of generation by 83%. Plants with capacity factors below 30% would not be profitable at the compensation levels used as a reference. Doubling the discount rates (5 to 10%) results in 30-35% cost increases; and doubling the plant size (50 to 100MW) results in 35% cost reduction.

[320] Average capacity factors of wind in Norway = 45% (2011). Average capacity factor of wind in Sweden = 20% (2011)



	A	B	C	D
Capacity factor	30%	30%	20%	30%
DR	5%	10%	5%	5%
Size-MW	50	50	50	100

Project operating results

	A	B	C	D	D'	D"
NPV (M$)	12	-17%	-26	96	110	30
IRR	8%	8%	2%	14%	15%	9%

Figure 148. Business cases – On-shore wind in Sweden (2012 US$/MWh)

Similar results are obtained for on-shore wind plants operating in Sweden. Revenues from reference prices, plus certificates would be in the range of 65-92 US$/MWh. This compensation results in positive incomes for projects with operating and technical characteristics which position them in the low ranges of cost (27-30% capacity, 5-6.5% discount rate, 50-100 MW). Costs for these plants could be at 62-100 US$/MWh. This would result in IRRs of 6-8% and NPVs of 1.3-13 MUS$ on average.

The results of the simulations of Swedish generation are significantly affected by the characteristics and operating regimes of each plant, as it is the case of Norway. A reduction from 30% to 20% in the capacity factor of a plant can increase costs of generation by as much as 40-45%. Plants with capacity factors below 27% are not profitable at the compensation levels used as a reference. Doubling the discount rate (5 to 10%) results in cost increases of 33%; and doubling the plant size (50 to 100MW) results in 31% cost reduction.

In summary, both in Norway and Sweden, on-shore wind plants with average to low capital costs and operating at high capacity factors may provide interesting opportunities to investors.

There may be leakage of projects from one country to the other? The cost differences shown by simulations are not significant enough to support the notion that plants in Norway or Sweden have noticeable cost advantages over those of the other country. Even if accelerated depreciation is used to evaluate the business case of off-shore wind in Sweden, the differences between the costs of generation of Norway and Sweden are very small. These differences do not provide sufficient evidence to state that investors in on-shore wind will prefer one country over the other as a matter of fact[321].

[321] The differences in the costs results obtained in each country are due to the characteristics of the plants included in the database of each country. Or in other words: the size of the cost differences is smaller than the confidence level of the simulations.

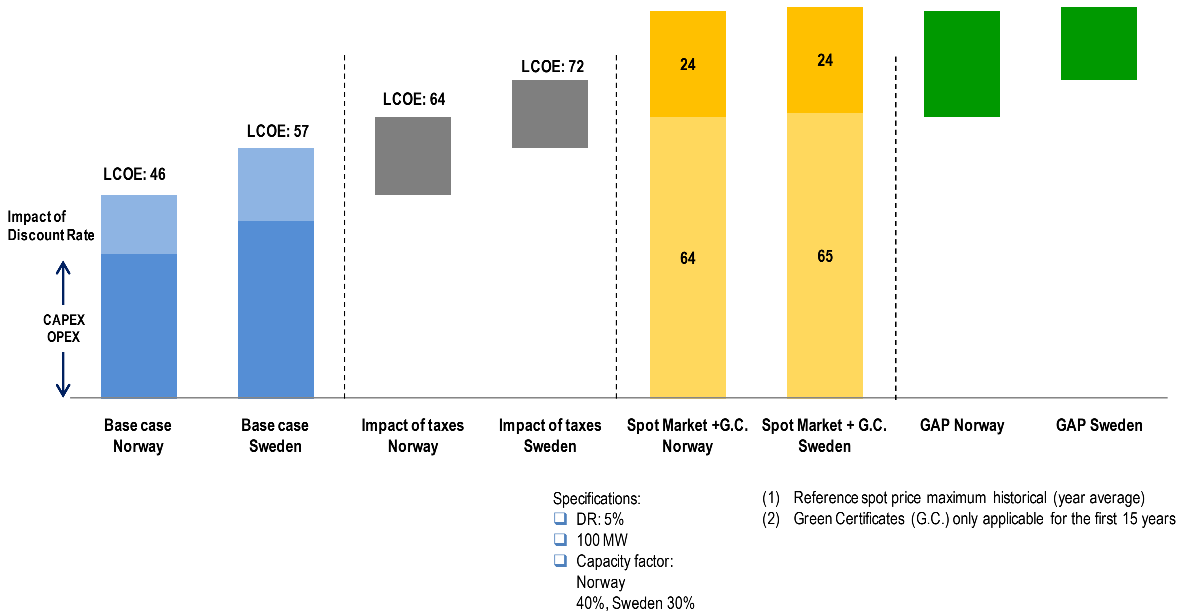


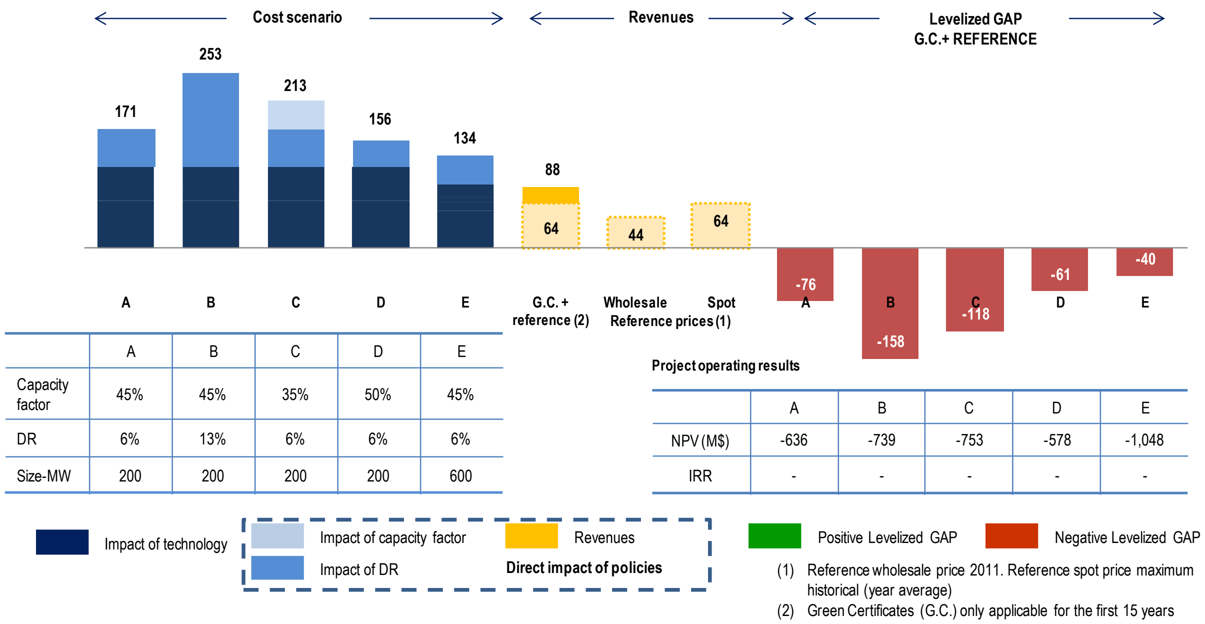
Figure 149. Business cases – Comparisons between Norway and Sweden (US$/MWh)

A statistical analysis of the sources and results of potential cost differences between countries would require a larger database of plants, with higher level of details that the one associated to RE-COST. This would increase the confidence levels of the simulations, and could potentially provide a different answer to the results presented in this report.

6.7.4 Detailed business cases – Norway and Sweden / off-shore wind

Off-shore wind generation shows a different picture from that of on-shore wind. At the current levels of prices for green certificates in Norway[322] and Sweden, it is unlikely that investors commit to the development of new off-shore plants. The business case for this technology is very poor in both countries.

[322] Data for Norway represent only projects or demonstration plants, not operating plants.



	A	B	C	D	E
Capacity factor	45%	45%	35%	50%	45%
DR	6%	13%	6%	6%	6%
Size-MW	200	200	200	200	600

	A	B	C	D	E
NPV (M$)	-636	-739	-753	-578	-1,048
IRR	-	-	-	-	-

Figure 150. Business cases – Off-shore wind in Norway (2012 US$/MWh)

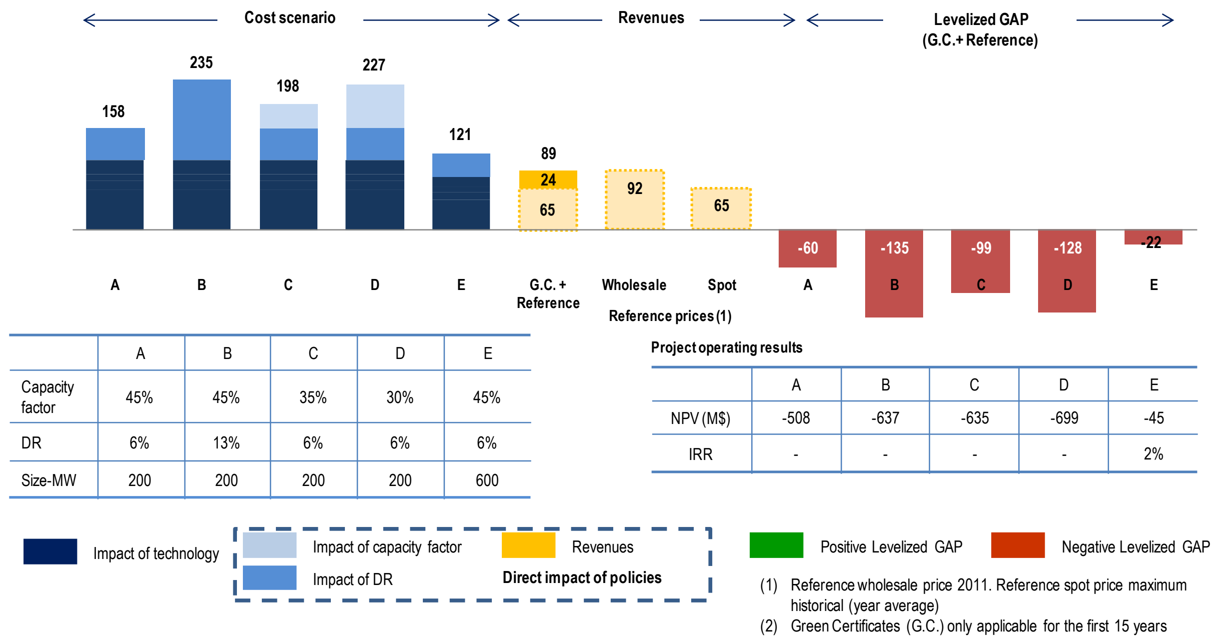
Simulations result in costs of off-shore wind projects in Norway in the range of 155-253 US$/MWh. Costs of off-shore wind projects in Sweden are similar, in the range of 138-234 US$/MWh. The compensation levels based on green certificates are not sufficient to cover the high costs of off-shore wind generation[323]. In addition, it is unlikely that the market price of electricity in any of the two countries rises in the short or medium term to the levels required to make off-shore wind profitable.

It may be contended that the picture represented in the current simulations is static and may not represent the future outlook of this technology. That if prices of green certificates significantly increase in the future, the outlook for off-shore wind might change. This enters the realm of the possibility. However, it is difficult to envision and scenario in which many investors will choose to commit to a still immature technology, with higher costs, and higher risks, when there is the possibility of investing in on-shore wind or hydro in Norway and Sweden, and in biomass in Sweden – with each technology providing larger revenue-cost gaps than off-shore wind.

The evidence from the market supports this assumption. Investors appear unlikely to commit to further off-shore developments in Norway and Sweden, if they are compensated only with the green certificates[324].

[323] Plants currently in operation have benefited from additional incentives. For instance, the Lillgrund Offshore Wind Farm (Sweden) has received incentives worth 20 M€.

[324] Vestavind Offshore has declared its intention to suspend project development of Havsul-1 until the current unfavorable conditions for off-shore development prevailing in Norway change. Enerdata 12/12/2012.



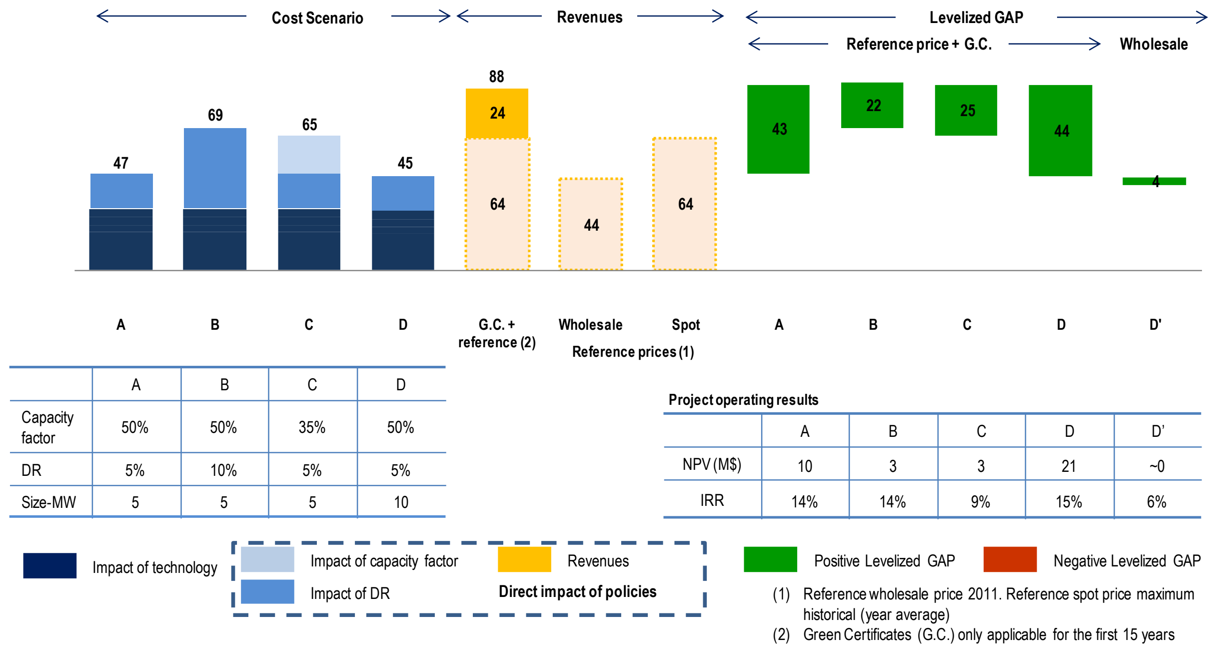
	A	B	C	D	E
Capacity factor	45%	45%	35%	30%	45%
DR	6%	13%	6%	6%	6%
Size-MW	200	200	200	200	600

Project operating results

	A	B	C	D	E
NPV (M$)	-508	-637	-635	-699	-45
IRR	-	-	-	-	2%

Figure 151. Business cases – Off-shore wind in Sweden (2012 US$/MWh)

6.7.5 Detailed business cases – Norway / Small hydro



	A	B	C	D
Capacity factor	50%	50%	35%	50%
DR	5%	10%	5%	5%
Size-MW	5	5	5	10

Project operating results

	A	B	C	D	D'
NPV (M$)	10	3	3	21	~0
IRR	14%	14%	9%	15%	6%

Figure 152. Business cases – Small hydro in Norway (2012 US$/MWh)

Simulations indicate that investors in these plants may define profitable business cases. However, given the large ranges of costs of hydro projects it would be necessary to count with a larger database of plants to confidently assert that every small hydro project is adequately compensated with the current incentive scheme in Norway and in Sweden.

6.7.6 Norway and Sweden – Lessons learned

On-shore wind: The green certificates scheme, as defined at the present (2012), appears to provide enough margins to new on-shore wind plants to ensure investors interest, while simultaneously preventing windfall profits. However, due to the relative youth of the joint scheme, it is not clear whether the incentive will be able to ensure attaining the growth targets defined by Norwegian and Swedish policy makers. Therefore, specific recommendations to improve or to modify are difficult to define at this point. More data and information, including actual results of plants operating under the green certificates scheme in real market conditions, would be required to consolidate lessons learned based on solid data.

Acquiring these data should not be complicated. Experts and policy makers should be enlisted to evaluate and analyze the impact of the joint scheme in the electricity sectors of both countries. Processes to evaluate the relative success of green certificates should be implemented. Publicizing the results of these evaluations would also encourage global experts to provide their input. Currently this global participation is somewhat difficult because information provided by Swedish and Norwegian policy makers and administrators in the electricity sector is limited, and some of it is only published in the local languages[325].

If future experience shows that there is a strong leakage of projects and capacity from one country to another, changes to the scheme would be recommendable. Several actions could be taken:

- For instance, if advantageous conditions in Sweden result on more on-shore plants build in Sweden than in Norway, the simplest way to ensure equal participation of plants in both countries would be to award rights of production specific for each country.
- Assigning 13.2 MW to Sweden and 13.2 MW to Norway will contribute to reduce leakage, but may defeat the joint aspirations of the scheme. This possibility should be contemplated only if additional analyses determine that the scheme is grossly disadvantageous to one of the two countries[326].

If in the future Norwegian and Swedish policy makers conclude that it is necessary to modify the current system, it may be possible to significantly affect its impact by modifying some levers. Of particular importance would be to ensure that the prices of certificates stay at a level high enough to provide sufficient margins to developers. This could be done by affecting the supply of available certificates – for instance, by accelerating or decelerating the pace of incorporation of new plants to the scheme, and therefore the demand-supply balance. These types of actions however may not be fully aligned with the desires of both governments to define a market driven system, not a centrally managed scheme as that of other countries included in the scope of RE-COST..

Off-shore wind: The analysis of off-shore generation shows that developing off-shore wind requires specific schemes that take into account the particular characteristics of this technology. Specific FIT may be successful – as demonstrated in Germany. Specific RFPs may also provide interesting returns to investors, as shown in France. However, technology neutral incentives do not appear to provide the right incentive levels to investors. When

[325] Given the prior experience of Sweden with the scheme, and the careful approach taken by Norway before committing to participating in it, it is clear that significant time and effort of experts has been devoted to analyze the potential advantages and disadvantages of joint green certificates. However, the system is not centrally controlled. It leaves a significant part of the results to the behavior of the markets. Processes and tools that ensure clear, immediate visibility of results are critical to identify unwanted outcomes and to quickly correct them.

[326] This doesn´t appear to be likely. Extensive analyses have been conducted prior to the definition of the joint green certificate scheme. In addition, the preliminary results from this study do not show a gross advantage of any of the two countries over the other. However, there is a gap in the scope of RE-COST that may result in incomplete insights: biomass generation, a very important source of generation with average lower costs than other RET, except hydro. It is much more important in Sweden than in Norway. Further analysis should be conducted to ensure there is no leakage of projects from Norway to new biomass plants in Sweden.

compensation across different technologies is the same, investors are likely to commit first to technologies with lower costs, which enable them to attain higher margins. Therefore, green certificates do not appear to be the best type of incentive to develop off-shore wind in Norway or Sweden today.

If policy makers in either Norway or Sweden decide that it is convenient to specifically develop off-shore wind, it would be necessary to define policies that recognize and address the specific characteristics of this technology, acting on several levers:

- Close the large gap between average costs of off-shore wind generation (155-253 US$/MWh in Norway and 138-234 US$/MWh in Sweden) and the reference prices of electricity (64-88 US$/MWh in Norway and 65-92 US$/MWh in Sweden).
- Reduce the technical risks of off-shore wind. For instance, ensuring priority feed to the grid, lower costs of connection to substations and guarantee grid connection allowing developers to attain lower rates of finance.
- Balance the resulting costs to consumers, or to taxpayers in Norway and Sweden, with other policy objectives.

The definition of potential policies to develop this technology would benefit from the experience attained in other regions.

However, at this point there is no clear evidence that leads to believe that either country desires to invest significant funds, time and effort in the development of off-shore wind in the short term. Both countries have enacted policies to support this technology, including tax exemptions (energy tax reduction), environmental bonuses (grants)[327], R&D funds, etc. But the funding requirements to provide a significant push to off-shore wind would be significantly higher than the support currently provided.

In addition, using off-shore wind as a mechanism to reduce emissions in the short term may not be as attractive in Norway and Sweden as in other countries. Norway has already 96% and Sweden counts with 52% installed capacity of RET (2011). Fostering other forms of renewable technology, such as on-shore wind and small hydro in Norway and Sweden and biomass in Sweden, may be faster and require less private and public expenditures.

6.8 Spain

Spain has a liberalized electricity sector. The regulator and responsible body for the organization of the Spanish electricity market is the Comisión Nacional de la Energía (CNE). The law distinguishes two types of electricity producers in Spain: ordinary regime producers and special regime producers[328]. Power generation is highly concentrated in five mayor companies, which generate most of the electricity in Spain (69.8% in 2011[329]): Endesa, Iberdrola, EDP - HC Energía, Gas Natural Fenosa and E.ON España. The transmission grid system is owned and operated by Red Eléctrica de España (REE). Distribution in Spain is dominated by two companies: Endesa, with 42% market share, and Iberdrola Distribución Eléctrica with 37%. The retail market is divided between regulated and

[327] Source: RES-LEGAL Sweden – 31.07.2012

[328] The special Regime includes electricity generation facilities below 50 MW and generated from waste, biomass, hydro, wind, solar and cogeneration. The ordinary regime includes all electricity generation facilities which are not included in the special regime.

[329] Source: Spanish energy regulator's national report to the European Commission 2012. CNE

liberalized markets. The liberalized market includes 105 companies, but the largest 5 account for 85% of the market[330].

Installed capacity in 2011 in Spain was 105.9 GW. Power sources consisted of a diversified mix: nuclear plants accounted for 7.3%, fossil fuels-fired plants for 48.2%, and 44.5% came from renewable sources. Spain is the second country in Europe in renewable installed capacity, and the eighth in the world.

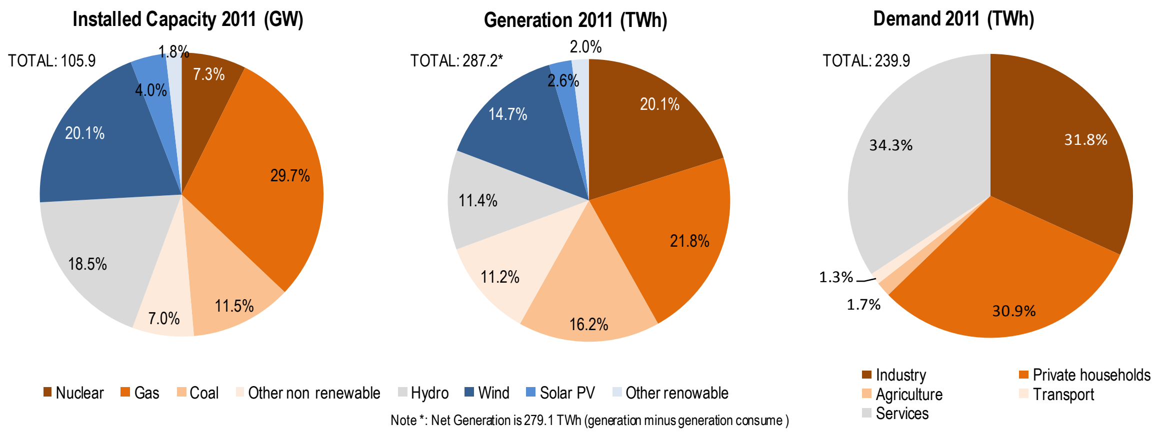


Figure 153. Spain – Installed capacity (MW) generation (TWh)[331] and demand (TWh) – 2011[332]

Generation in Spain was 287.2 TWh in 2011. Nuclear generation accounted for 20.1% of the total, fossil fuel generation for 49.2%, and generation from renewable sources for 30.7% (hydro 11.4%, wind 14.7%, solar PV 2.6% and other renewable 2.0%). The importance of RET in the Spanish supply mix is increasing over time.

Electricity price formation: Spain and Portugal have integrated their electricity markets into MIBEL (Mercado Ibérico de la Electricidad). The market was launched in November 2001. OMIP, the futures market, is organized by Portugal. Spain is responsible for the organization of OMIE, the spot market. Electricity is traded through a variety of mechanisms: long-term markets (OTC contracts or futures market); daily market (day-ahead market); intraday market; short-term market; and auctions (fixed price). The market clears supply and demand and publishes the results, indicating the amount of electricity that each producer must generate to meet the expected demand, and the price for every hour of the next day[333].

Generation projects: The latest official projections for the electricity sector in Spain were carried out in 2011, in the framework of the PER 2011-2020 (Plan de Energias Renovables). The plan used 2010 as the base year. The largest increase in installed capacity was forecast to come from solar PV, which was supposed to increase up to 12.1 GW; followed by on-shore wind, which was forecast to reach 35,750 MW of installed capacity in 2020[334].

[330] Source: CNE official website; REE official website; Informe de Supervisión del mercado minorista de electricidad. Comisión Nacional de la Energía

[331] Source: El Sistema Eléctrico Español –Informe 2011 (REE: Red Eléctrica de España)

Gas includes Fuel/Gas technologies and CCGT

Other non-renewable includes non-renewable technologies within the "Special Regime"

Biomass installed base is included in other renewable technologies

[332] Source: Informe anual de consumos energéticos. Año 2010 – IDAE

[333] Source: Informe del Mercado 2011. OMIE

[334] Source: Plan de Energías Renovables 2011-2020. IDAE

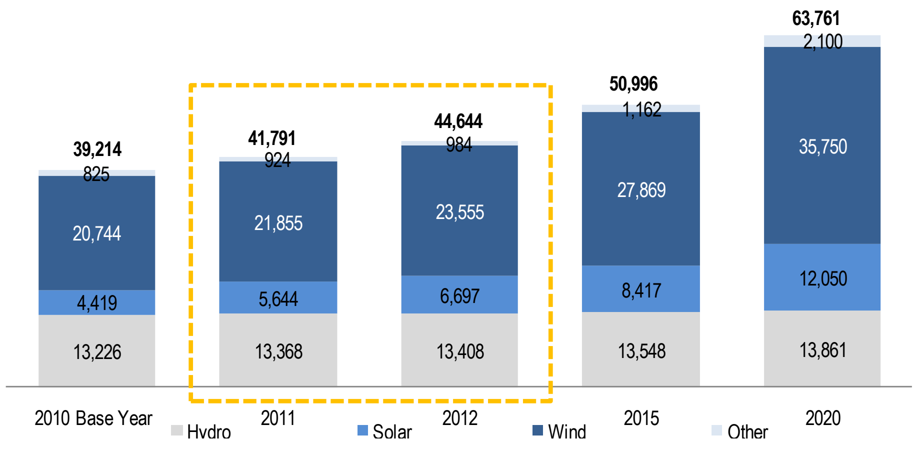


Figure 154. Spain – Installed capacity plans (MW) 2011-2020

Although some of the experts interviewed for this study in 2012 claimed that the targets set by the PER for 2015 and 2020 might still be valid, it is very likely that the PER 2011-2020 will have to be thoroughly revised, in light of the economic crisis affecting Spain since 2008.

Incentives to generation: The main incentive to electricity generation in Spain has been feed-in tariffs (FIT) to the special regime. Regulated FITs were paid to eligible solar, wind (on-shore), hydro and other renewables for the first 20 to 30 years of operation (depending on the technology).

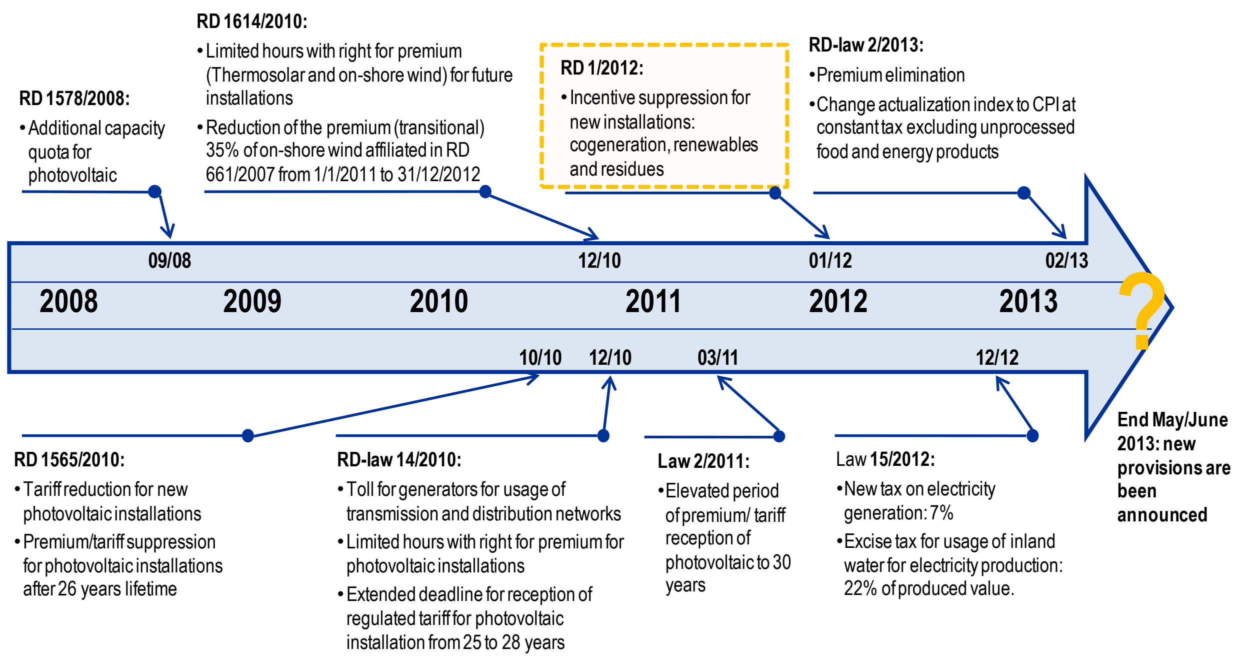


Figure 155. Spain – Modifications of legislation affecting the remuneration of the special regime (2008-2013)

The FIT levels have been revised several times during the life of the scheme[335]. In January 2012, the Spanish government imposed a temporary suspension of additional economic support approvals for new generation capacity under the special regime. But all the plants that were commissioned, or at least pre-registered, before

335 Ministry of Industry, Energy and Tourism – *"Tarifas categoría b enero 2012"*

2012 will still receive their approved FIT[336], with the exception of solar PV. In addition, the RD 14/2010 establishes a cap on the maximum number of hours in which plants can receive the FIT. This measure is retroactive.

TECHNOLOGY	INCENTIVES
ON-SHORE WIND	No support scheme available for plants coming into operation after January 2012. **Feed-In-Tariff** (20 years) • <20y = 8.1270 €¢/kWh (10.57 US$¢/kWh) • >20y = 6.7921 €¢/kWh (8.83 US$¢/kWh) **Or Premium Tariff**
OFF-SHORE WIND	n.a.
PHOTOVOLTAIC	No support scheme available for plants coming into operation after January 2012. **Feed-In-Tariff** (30 years)[337] • P≤100kW: 30 years 48.8743 €¢/kWh (63.54 US$¢/kWh) • 10kW<P≤10MW: 30 years 46.3348 €¢/kWh (60.23 US$¢/kWh) • 10MW<P≤50MW: 30 years 25.4997 €¢/kWh (33.14 US$¢/kWh)
HYDRO POWER	No support scheme available for plants coming into operation after January 2012.[338] **Feed-In-Tariff** (25 years) • <25y = 8.6565 €¢/kWh (11.25 US$¢/kWh) • >25y = 7.7909 €¢/kWh (10.13 US$¢/kWh) **Or Premium Tariff**
CCGT	n.a.
COAL	Coal incentives

Also REEEP (Renewable Energy & Energy Efficiency Partnership) for all technologies

Figure 156. Spain – Incentives to electricity generation (example, not comprehensive)

Additional information on applicable tax schemes can be found in Figure 101.

6.8.1 Detailed business cases – Spain / On-shore wind

On-shore wind in Spain has been incentivized in the past with a number of different schemes. Incentives have been changed over time to satisfy different policy objectives, and to reflect the evolution of technical factors and operating conditions of eligible plants. Plants commissioned before January 2012 will receive a FIT set at 106 US$/MWh. Plants commissioned after this date are not eligible to receive any FIT. They will have to sell their production at market prices, although they may still benefit from priority feed-in. The new 6% tax on electricity sales defined in September 2012 also applies to wind generation. Its true impact over generation revenues is uncertain, because utilities are likely to pass part of this additional cost to consumers. But the announcement has contributed to increase investor uncertainty.

Developers of on-shore wind may still enhance plant profitability through grants or other measures based on local and regional government support. But these measures are much more restricted than in the past.

[336] Throughout 2012 additional measures have been taken within the electricity sector whose main objective has been to reduce the tariff deficit resulting from conditions set by the government and generators: Tax on electricity production: 6% for every technology, revision of the remuneration for ordinary regime plants, reduction of the maximum volume of production and energy prices for indigenous coal plants in 2012, reduction of the incentive to capacity investment and the environmental incentive in 2012.

[337] RD 14/2010 established an equivalent operating hour limit for solar PV installations depending on climate zone and technology.

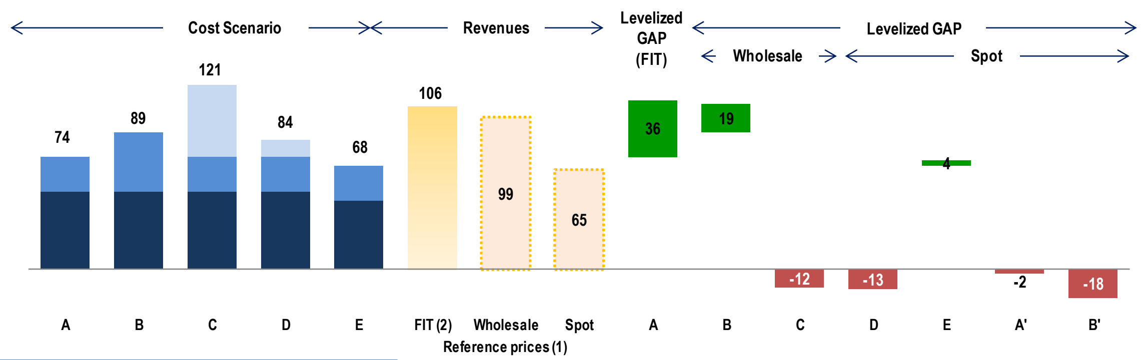
[338] Royal Decree-law 1/2012: whereby the pre-allocation of remuneration procedures for new electricity generation under a special regime is suspended.

LCOEs of on-shore wind in Spain may reach levels lower than those for some new plants of other technologies. Simulations result in generation costs in the range of 70-110 US$/MWh. A number of factors account for these results:

- Spanish actors in the electricity sector have extensive experience in on-shore wind. This contributes to enhance the business case of this technology.
- Some plants are at the forefront of technical development, attaining costs in lower ranges of the technology (70-90US$/MWh).

With the latest tariff scheme (106 US$/MWh for plants entering operation before 2012), the business case of a new on-shore wind plants plant is attractive. Investors attain returns of 10-15% IRRs, NPVs >0, and positive income over the lifetime of the plant.

With no incentives, best-in-class plants (75-100 MW, with high 30-35% capacity factors and 6-8% financing rates) could turn a profit only if they can operate at revenue levels higher than the average spot market. Prices of 84-99 US$/MWh would provide relative good returns: 8-12 % IRR, NPVs >0 and positive income over the life of the project. But the business case of the plant would be negative if something fails. These apparent good results may attainable only on paper.



	A	B	C	D	E
Capacity factor	35%	35%	20%	30%	35%
DR	6.5%	10%	6.5%	6.5%	6.5%
Size-MW	50	50	50	50	100

Project operating results

	A	B	C	D	E	A'	B'
NPV (M$)	44	15	-15	-21	-1	-9	-24
IRR	14%	14%	5%	4%	7%	6%	6%

Impact of technology
Cost of fuel
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP

(1) Reference Wholesale price 2011. Reference Spot price maximum year average
(2) Abrogated. Updated annually with CPI minus 50 basic points

Figure 157. Business cases – On-shore wind in Spain (2012 US$/MWh)

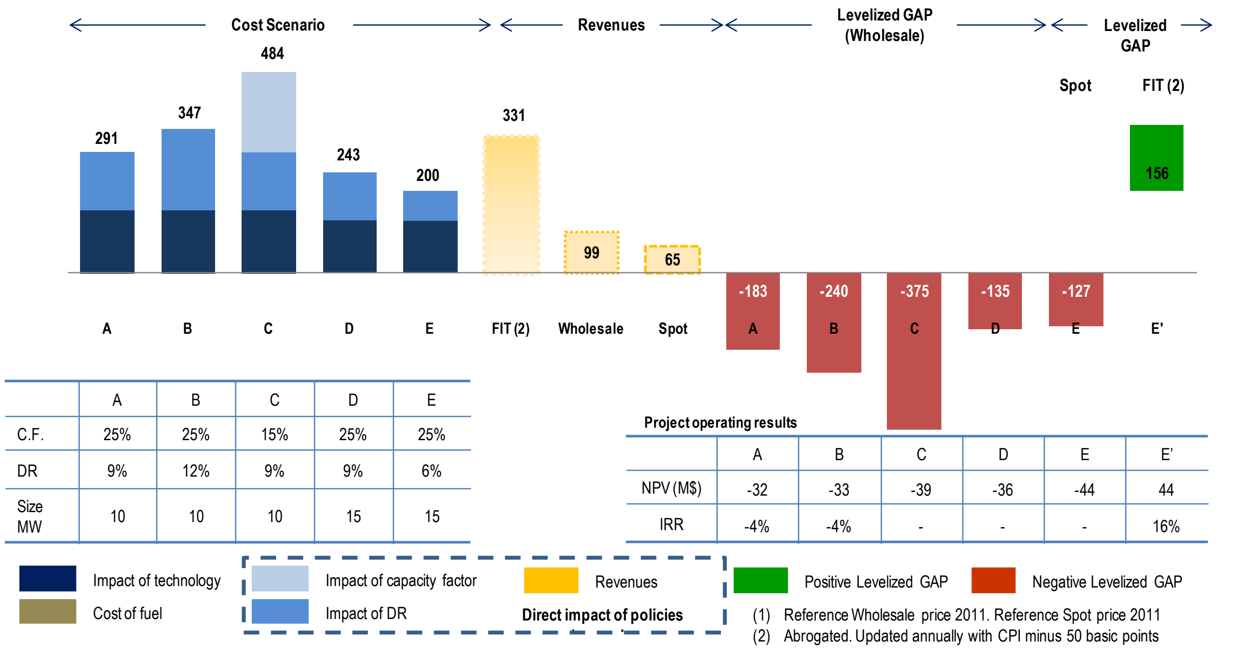
Plants operating at lower market prices (65-70 US$/MWh), or at capacity factors lower than 20% are unlikely to present business cases interesting for investors.

In summary, in Spain as in other countries, on-shore wind appears to be closing the gap between the costs of generation and the prevailing (average) market prices. But, average plants (20-30 MW, 20-25% capacity factor and 6-12% discount rate) are still unprofitable without incentives. In addition, the actions of the Spanish policy makers have created high levels of uncertainty in the sector. This is likely to result in very few on-shore wind developments in Spain in the short term. Developers and manufacturers are looking abroad for new opportunities.

6.8.2 Detailed business cases – Spain / Large solar PV

With the tariff levels applicable before 2012, solar PV plants in Spain were providing reasonable returns to investors. Plants of average size (10-50 MW) were awarded a FIT of 331 US$/MWh. Solar PV plants, with 200-350 US$/MWh average cost, could turn a profit. Simulations show that plants eligible to receive the tariff, operating at 15-25% capacity factors, and 6-8% discount rates, could attain 10-15% IRRs and positive NPVs.

Without incentives the case for new solar PV plants appears rather doubtful. Put simply: currently it is not possible to generate the revenues needed to make a project profitable. Large solar PV plants in Spain operating in the grid may break-even only if capital costs drastically plunge. Some European developers interviewed claim to be able to build solar PV plants with capital costs 50% lower than the current average. But even at these very low costs, solar PV plants would find it difficult to turn a profit at the current reference prices in Spain.



	A	B	C	D	E
C.F.	25%	25%	15%	25%	25%
DR	9%	12%	9%	9%	6%
Size MW	10	10	10	15	15

Project operating results

	A	B	C	D	E	E'
NPV (M$)	-32	-33	-39	-36	-44	44
IRR	-4%	-4%	-	-	-	16%

Figure 158. Business cases – Solar PV in Spain (2012 US$/MWh)

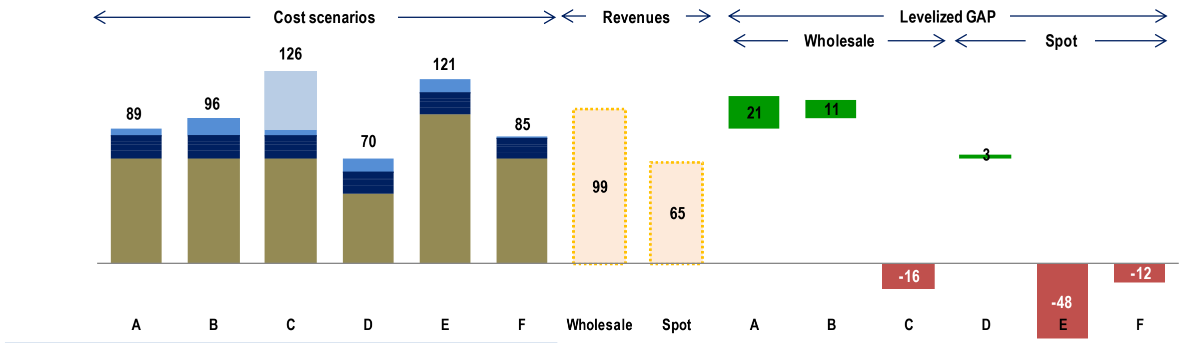
There may be some exceptions to this general rule. If the solar PV plant operates in very specific conditions it may be possible to define a potentially attractive business case. Examples include when the plant is part of a distributed generation development. In this case, its business case would not be computed with the electricity market price, but with the retail or industry electricity prices. These prices in Spain may be 40-50% higher than the market prices of electricity. Other exceptions would also be possible; for instance, if the plant competes against generation alternatives with significantly higher costs than the reference market prices (plants in islands or in isolated locations).

6.8.3 Detailed business cases – Spain / CCGT

The price of gas is determinant to the cost results of gas-fired plants. Gas prices in Spain are mostly set by international markets. The margin of maneuver for investors is limited in this aspect. The simulations use gas prices of 10-11 US$/MMBtu. Additional factors that contribute to defining attractive business cases for gas-fired plants include high capacity factors – reducing plant capacity from 75% to 25% may result in a 40-50% increase of LCOE; and defining the role of the plant to ensure additional revenues (for instance compensations for ancillary services, guarantee of power or availability). Other factors such as plant size and transmission costs are also relevant, but their influence over generation costs is much lower.

Plants able to access revenues in the average to high end of the simulated range may present attractive business cases to investors, if the capacity factor of the plant is high. Simulations show that a 400 MW plant, at 40-75% capacity factor may turn positive profits. Plants at capacity factors below 40-50% find it difficult to reach profitability, even with enhanced revenues.

Plants that operate at the low end of the ranges of reference prices will find it difficult to present attractive business cases to investors. Only plants with very low costs (large, and with capacity factors at 75% or higher) may break-even at the reference spot price of electricity (average 2011). But their business case would be very thin after adding taxes. The capital would be barely compensated under these conditions.



	A	B	C	D	E	F
Capacity factor	75%	75%	25%	75%	75%	75%
DR	8%	15%	8%	8%	8%	8%
Size MW	400	400	400	400	400	850
Fuel Cost	Avg.	Avg.	Avg.	-30%	+50%	Avg.

Project operating results

	A	B	C	D	E	F
NPV (M$)	463	123	-150	29	-1,136	-635
IRR	23%	22%	4%	10%	-	-

Impact of technology
Cost of fuel
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP
(1) Reference Wholesale price 2011. Reference Spot price 2011

Figure 159. Business cases – CCGT in Spain (2012 US$/MWh)

Under these conditions, investors are likely to be wary of committing to significant developments of this technology in the short term. The emergence of Spain from the current economic crisis may result in higher capacity factors for thermal plants, in higher prices of electricity, or both. However, at the present there is no assurance of when the turning point for the crisis will occur, and of the speed of recovery.

6.8.4 Detailed business cases – Spain / Coal

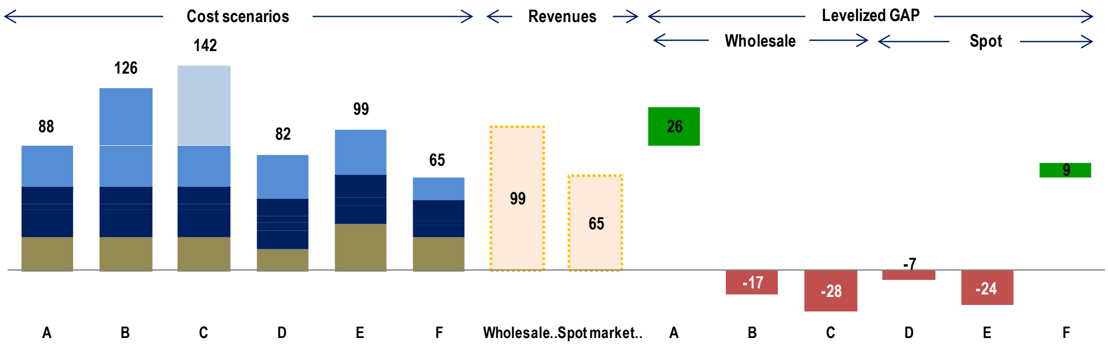
Most of the simulations of new coal-fired plants in Spain result in very poor business cases. LCOE ranges for coal generation are 75-140 US$/MWh. With the reference market prices at 65-99 US$/MWh, some plants might theoretically be profitable; but it would be necessary to very specifically align a number of factors:

- Plants have to be large. The impact of size is significant. Increasing the size of a plant by 50% (400-600 MW), results in LCOE reductions of at least 20-25 US$/MWh.
- Coal prices have to be at international levels. The simulations shown use coal prices of 2-2.5 US$/MMBtu.

- The plant must reach at least 45% capacity factor[339].
- Finally, the plant should reach compensations levels above the spot market price used as reference (2011).

Prices at 99 US$/MWh provide a positive business case to large plants, with very high capacity factors, using coal at internationally priced levels. Reference spot market prices of electricity may provide enough revenues to good plants to break even. But the business case would be thin. Compensation to investors would be very low or nil (case F in Figure 160).

A conjunction of all these favorable factors is possible in paper, but it will not be easy to accomplish in the current conditions of the electricity sector in Spain.



	A	B	C	D	E	F
Capacity factor	60%	60%	30%	60%	60%	60%
DR	8%	15%	8%	8%	8%	8%
SIze MW	400	400	400	400	400	600
Fuel Cost	Avg.	Avg.	Avg.	-30%	+50%	Avg.

Project operating results

	A	B	C	D	E	F
NPV (M$)	413	-237	-373	-231	-564	190
IRR	13%	12%	5%	7%	3%	11%

Impact of technology; Cost of fuel; Impact of capacity factor; Impact of DR; Revenues; **Direct impact of policies**; Positive Levelized GAP; Negative Levelized GAP

(1) Reference Wholesale price 2011. Reference Spot price 2011

Figure 160. Business cases – Coal-fired in Spain (2012 US$/MWh)

The likelihood of significant change in the short to medium term (next 3-4 years) is low. The emergence of Spain from the current economic crisis may result in higher average capacity factors and higher electricity prices. Higher levels of demand might trigger these increases at some point in the future.

This is likely to result in low interest in this technology in the short term, since investors would be required to make multi-million (900-1,000 MUS$) commitments to build a plant whose business case in the short term is poor, and in the long term, uncertain.

6.8.5 Spain – Lessons learned

Policy makers in Spain are broadcasting a strong desire to significantly reduce the incentives awarded to RET. Budgetary constraints, and the perception that some plants already commissioned could be attaining windfall profits, are at the heart of the issue.

[339] Average capacity of coal-fired plants in Spain in 2011 was 43%.

General recommendations – new RET development: The previous policies for RET development in Spain have been successful in a number of aspects. Spain counts currently with 49,395 MW[340] of RET installed capacity (solar PV, on-shore wind, hydro and others). Without policies designed to support these technologies, it is doubtful Spain would be enjoying today these high levels (~25%) of RET in the generation mix of the country. RET development has resulted not only in a significant proportion of clean sources of generation in Spain, but also in technology development and innovation. Spanish companies, active in the full supply chain of RET generation, compete today worldwide. Some of them are leaders in their specific sub-sector. This in turn has contributed to significantly enhance economic growth in the country.

But poor implementation of some policies has resulted in a number of factors that are significantly damaging the situation of the RET sector in Spain, and its recovery chances in the short term.

- FIT and other incentives may not have been well adapted to specific technology characteristics. There are few definitive analysis of profitability of RET developers in Spain. But the rush to develop up to 63,761 MW of RET by 2020 appears to point at excellent rates of return, which are confirmed by the simulations carried out in this study.
- There was no cap structure that would limit the funds awarded to developers. It is not clear that previous Spanish policies have balanced in an optimal way the benefits attained by the deployment of RET, with the costs associated to that deployment.
- Sudden changes of direction and mixed messages about the future structure of policies and retroactive decisions have resulted in high levels of investor uncertainty.

It is necessary to redefine the basis for the development of RET in Spain. Higher level policies, with clear objectives, and with strong economic implications are required.

- Define clear objectives for future RET development that optimally balance the direct and indirect benefits pursued with the funds required. In particular, it would be advisable that RET development plans included deep and complete analyses of the funds necessary to implement them.
- Adopt a holistic approach. RET deployment plans should specifically evaluate their resulting impact on other forms of generation, and on the future prices of electricity in the country.
- Optimize messages and communication vehicles to prevent uncertainty about future developments.

Some modifications of the policies applicable to plants in operation may be unavoidable, but they should be kept to a minimum.

- Retroactive policies that significantly change the incentives enjoyed by existing plants should be avoided to prevent generating mistrust towards Spanish policy makers.
- However, the RET sector should also face market implications as other sectors in Spain. It may be difficult to justify entirely stable polices for RET, while every other sector in Spain is suffering from significant reductions in public expenditures some of them also retroactive.

On-shore wind: Results from simulations show that new on-shore wind plants in Spain still require some measure of incentives to provide positive business cases to investors. Only plants operating off-grid, in very remote locations or in islands, may be attractive at the market prices of electricity, because they compete against more expensive generation alternatives.

[340] Source: Preliminary report 2012. Red Eléctrica de España (REE)

It may be possible to support the on-shore wind sector without employing large amounts of funds.

- Do not significantly change the existing FIT awarded to plants that started to operate before 2012. Implementing drastic retroactive measures may marginally contribute to reduce the total costs of generation, but it will certainly generate significant qualms about any future scheme launched by Spanish policy makers.
- Consider to reduce taxes to sales of electricity. It is not clear that this measure significantly affects the revenues of large utilities, but it may put at risk the business case of smaller developers. Potentially substitute the blanket tax with a scheme that only reduces the likely windfall profits of some plants.
- Maintain priority feed-in for on-shore wind. Without this measure, not only new plants, but also existing plants may see their financial results seriously compromised.
- Launch clear and unambiguous messages about the short term measures applicable to the sector. Uncertainty about the intentions of policy makers and frequent reversals of decisions already announced do not contribute to increasing investor confidence.

Solar PV: If in the future policy makers in Spain desire to continue growing solar PV at the rates of the past it would be necessary to continue providing support to this technology. Best-in-class, new solar PV plants (10-20 MW, 20-25% capacity factor and 5-8% discount rate) would need a tariff of at least 250 US$/MWh to display attractive business cases to investors. Solar PV plants with breakthrough developments that significantly reduce their costs would need a much smaller FIT (100-120 US$/MWh) to turn a profit high enough to interest investors. Providing this small tariff would ensure that only plants that incorporate significant technology developments are built in the future in Spain.

Another possibility that would not require direct incentives would be to award grants to very specific solar PV plants to accelerate the rate of implementation of technology breakthroughs. This could be done by providing funds for R&D projects specifically focused in raising efficiency and plant productivity through new technology developments.

Any recommendations must take into account the current direction of electricity policies in Spain. Proposals to return to a FIT system similar to the one active in the past are unlikely to be successful. But, it may be feasible to define an incentive system that focuses only on breakthrough projects, with significantly lower generation costs than the average RET plant. For instance, reducing the levels of the FITs, and putting a cap in the public funds devoted to these incentives would ensure that only a limited number of plants, with characteristics which position them in the low ranges of cost would receive support. This would maintain the industry alive, and simultaneously contribute to accelerate innovation, as well as technical and operational developments.

It would also be possible to define an RPS system that contributed to support further development of RET, for instance, offsets. Defining such a system would have to take into account the current status of other forms of generation, and the situation of the Spanish market. Offsets based on payments from less clean forms of generation, such as gas-fired and especially coal-fired plants, may increase the strain suffered by many of these plants due to low capacity factors. Making the electricity customer pay for the incentive – similar to the green certificate scheme – may be unfeasible in the short term, given the current situation of the Spanish economy. However, it may be considered in the medium term when the crisis abates.

6.9 Japan

Starting in 1995, four different rounds of progressive liberalization have taken place in Japan. The main responsibility for the electricity sector lays within the Ministry for Economy, Trade and Industry (METI), primarily through the Agency of Natural Resources and Energy (ANRE). The Japanese electricity market is dominated by 10 vertically integrated companies (EPCOs), which manage the entire power value chain from generation to retail within their areas of influence. Additional actors are two wholesale utilities with 2.6 GW of installed capacity; 66 power producers and suppliers (PPSs); 5 specific electric utilities (SEUs), which generate, transmit, and supply electricity to a specific territory[341]; and a large number of self-producers, who generate electricity for their own needs[342].

Transmission capacity is mostly under the ownership of the EPCOs, although the wholesale companies and the SEUs also own transmission lines. Interaction between utilities has been limited so far. EPCOs balance supply and demand in their own service areas. This has compelled utilities to be self-sufficient, and to have enough generation capacity on stand-by to always meet peak demand on their own.

The Tōhoku earthquake and tsunami of March 11, 2011 significantly affected the electricity sector in Japan. It led to the meltdowns of the Fukushima Daiichi ("Fukushima One") nuclear power plant, and to the immediate shutdown of several other power plants, taking a total of 24.8 GW of generating capacity offline[343]. These events and their consequences have put a severe strain on utilities, as nuclear plants have been gradually shut down for scheduled maintenance, and only two have received permission to be restarted yet[344]. The accident at Fukushima Daiichi has shaken the Japanese public's faith in the safety of nuclear power, with large majorities in public opinion pushing for the complete phase-out of nuclear power. The gradations of opinion are restricted to the pace at which this new policy direction should be implemented.

Installed Capacity: At the end of the fiscal year of 2011 installed power capacity in Japan was 285.7 GW[345]. The main energy source was thermal plants, fuelled with a mix of oil, coal and gas (LNG), which accounted for 65% of total capacity. Hydroelectric and nuclear power plants used to be the second and third pillar of the Japanese power mix, with 17% each of installed capacity. Other non-hydroelectric RET, with 3 GW, represented only 1% of the total installed capacity in the country.

Generation: Japan produced 1,107.8 TWh of electricity in the fiscal year 2011[346]. 81.9% was generated by thermal plants. Nuclear power production in 2011 amounted to only 9.2% of the total. This was much lower than in past (average production in 2010 was 25%), because a significant part of the Japanese nuclear fleet was shut down in this year. The remaining 99 TWh (8.9% of the total) came from renewable sources (8.3% from hydro and 0.7% from other renewables, mostly from wind farms)[347]. The share of renewables rises to 10.9%, if biomass and waste is included (otherwise included in thermal).

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[341] Source: Federation of Electric Power Companies (2011) "Handbook of Electric Industry". Also: ANRE, Power survey statistics catalogue, table of power stations' licensed outputs, 2012. (http://www.enecho.meti.go.jp/info/statistics/denryoku/result-2.htm)

[342] Neither of the above sources keeps track of the number of these players. METI sources didn´t confirm the ministry is aware of the specific number of suppliers. ANRE's power survey statistics catalogue lists 3,199 power stations with a combined capacity of 55.8 GW in its 2011 table of licensed outputs of power stations for in-house use.

[343] Source: Bloomberg – Japanese Power Plants Damaged, Closed by Quake, Tsunami, 27th April 2011

[344] Source: http://www.world-nuclear.org/info/inf79.html

[345] Source: ANRE, Power survey statistics catalogue, 2012.

[346] A Source: NRE, Power survey statistics catalogue, 2012.

[347] Difference due to statistical rounding.

Demand: 931 TWh of electricity were consumed in Japan in 2010. 62% was demanded by deregulated customers served by the EPCOs. The second largest consumer group was residential customers with a power consumption of 304.2 TWh in 2010 (33%). Other consumer sectors, such as commercial and industrial customers, customers in designated service districts, and consumption of station operation, accounted for a relatively small percentage of power demand (5.6%).

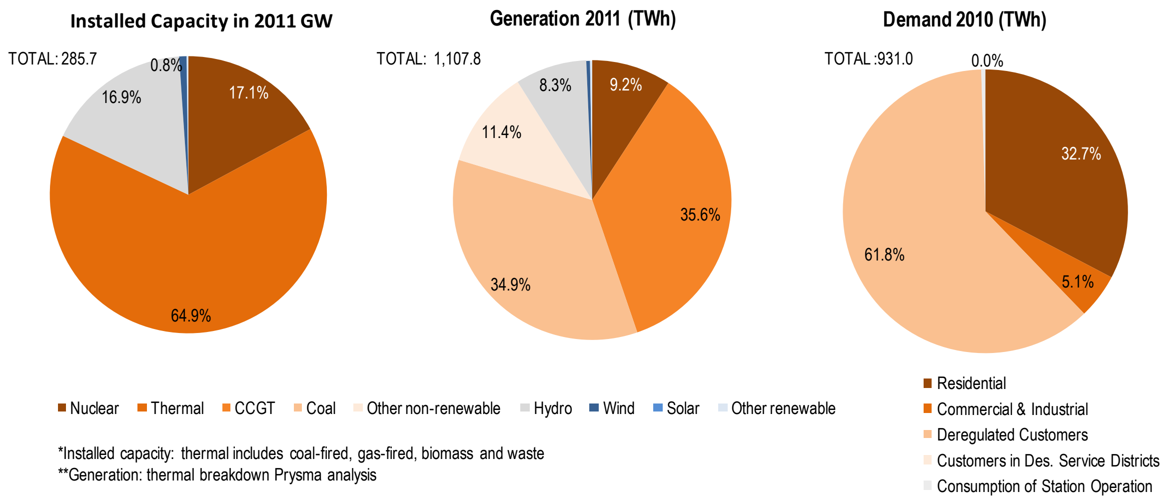


Figure 161. Japan – Installed capacity (GW) and generation (TWh) – 2011[348] and demand (TWh) – 2010[349]

Generation Projects: Before 2011, plans in Japan called for a threefold increase of power generation by 2030. Until the Fukushima accident the Japanese energy policies assumed a significant growth of nuclear power[350]: Building 8 additional power plants by 2020, and another 6 by 2030, adding to the 54 already running in 2010. The goal was to use nuclear power to produce 53% of the electricity needed in Japan by 2030. This large increase of nuclear power had to be revised. A Committee on Basic Energy Issues, that included experts from various stakeholder groups, was created in October 2011 and tasked to create a new Basic Energy Plan. The Committee produced three scenarios for the Cabinet which informally announced it would consider a reduction of Japan's reliance on nuclear power to 0% by the 2030s, through the implementation of three principles: to cap nuclear reactor lifetimes to 40 years; to not restart reactors without the safety approval of the new Nuclear Regulatory Authority; and to not engage in the construction of additional reactors[351]. These principals were never formally adopted and today this reduction in nuclear power reliance is under scrutiny. It is not clear at this point how the power mix in Japan will evolve, especially as the new government inaugurated in late December 2012 has stated its intention to review its predecessor's attitude towards the nuclear phase-out[352].

Electricity Price Formation: The official trading platform for electricity in Japan is the Japanese Electricity Exchange (JEPX). But only 0.7% of the electricity consumed in the country was traded in it in 2011. The JEPX, founded in November 2003 after the third round of market liberalization, hosts the Spot Market, where 48 products are traded in a single auction system; the Forward Market, for fixed-Form and Bulletin Board Products, gives the option to hedge future risks. Its impact on average electricity prices appears to be low. Wholesale prices of

[348] Source: ANRE Power Survey Statistics Catalogue 2012 (fiscal 2011).

[349] Source: Federation of Electric Power Companies (2011) "Handbook of Electric Industry".

[350] Source: The Strategic Energy Plan of Japan. Meeting Global Challenges and securing energy futures (Revised in June 2010). METI.

[351] Source: Statement of the Energy and Environment Research Council, a sub-Cabinet body, of September 6, 2012.

[352] Source: News from the 27th December 2012 http://rt.com/news/nuclear-japan-plant-government-932/

electricity, determined by bilateral contracts or by transfer prices within the EPCOs, are very difficult to obtain, because the key stakeholders do not usually disclose them to the public. Most end-users in the liberalized sector buy electricity directly through long-term bilateral contracts with a power producer[353].

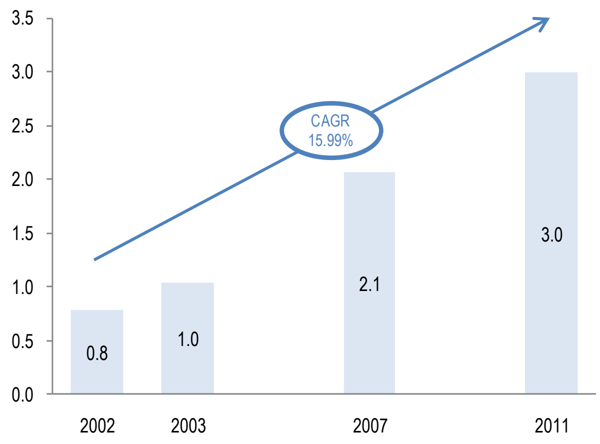


Figure 162. Japan – RET development (2002-2011)

Incentives to Generation: In April 2003 Japan enacted the RPS law aiming to promote new renewable technologies, which obligated electric utilities to use a steadily rising percentage of generated renewable energy. This system was abandoned in 2011. Today the most significant support system for RET is feed-in tariffs (FITs). The scheme was launched in July 2012 accepting the first project applications. In most cases the tariffs are paid for gross electricity generation. The exception is tariffs for household solar generation, where the principle of net production was maintained in order to stimulate domestic energy savings[354]. The additional costs from the tariffs are financed through a surcharge on the electricity bill of all end-users, although industrial users with a particularly high level of consumption, as well as users from areas afflicted by the 2011 earthquake, receive substantial exemptions.

The compensation levels are calculated with a view to covering developers' grid connection costs, real estate costs, and corporate taxes. The tariff levels are subject to review on a yearly basis.

<table>
<tr><th>TECHNOLOGY</th><th>INCENTIVES</th></tr>
<tr><td>ON-SHORE WIND</td><td rowspan="2">Feed-In-Tariff (20years) since July 2012.
• <20kW 57.75 ¥/kWh (0.74 US$¢/kWh)
• ≥20kW 23.1 ¥/kWh (0.29 US$¢/kWh)
Other
• 100% depreciation deduction for the 1st year
• Tax base reduction for depreciable assets</td></tr>
<tr><td>OFF-SHORE WIND</td></tr>
<tr><td>PHOTOVOLTAIC</td><td>Feed-In-Tariff (20years) since July 2012.
• 42 ¥/kWh (0.54 US$¢/kWh)
Other
• 100% depreciation deduction for the 1st year
• Tax base reduction for depreciable assets</td></tr>
<tr><td>HYDRO POWER</td><td>Feed-In-Tariff (20years) since July 2012, before RPS.
• <200kW 35.7¥/kWh (0.46 US$¢/kWh)
• 200kW≤P<1MW 30.45 ¥/kWh (0.39 US$¢/kWh)
• 1MW≤P<30MW 25.2 ¥/kWh (0.32 US$¢/kWh)
Other
• 100% depreciation deduction for the 1st year
• Tax base reduction for depreciable assets</td></tr>
<tr><td>CCGT</td><td>n.a.</td></tr>
<tr><td>COAL</td><td>n.a.</td></tr>
</table>

REEEP (Renewable Energy & Energy Efficiency Partnership) – applicable for all technologies

Figure 163. Japan – Incentives to electricity generation (example, not comprehensive)

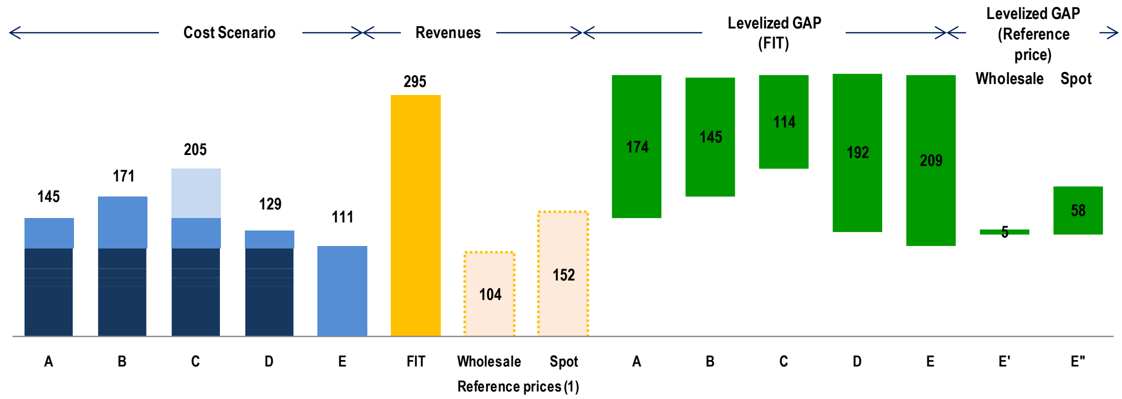
[353] Source: IEA

[354] Not in the scope of this study.

6.9.1 Detailed business cases – Japan / On-shore wind

Costs of on-shore wind in Japan are approaching market prices. But, most on-shore wind plants in Japan require incentives to deliver attractive business cases to investors. Even plants with characteristics that position them in the low ranges of generation cost (capital costs < 74 US$/MWh, capacity factors > 30%, financing rates < 5%), cannot break even at the current wholesale prices in Japan (80-104 US$/MWh). At spot prices[355] (152 US$/MWh), plants positioned in the low ranges of cost could attain positive incomes; but the resulting business cases would be thin (96.8 MUS$ NPV, 11% IRR).

In contrast, with the current FIT scheme in Japan (2012), even plants that do not operate in very good conditions may be able to realize attractive returns, if they ensure connection to the grid. With compensations in the range of 295 US$/MWh in 2012, plants with average or good levels of generation costs (145-205 US$/MWh) appear to result in quite attractive business cases (high IRR, NPV >0, income > 0). Even plants with high financing rates (10%-12% and up to 19%), or with low capacity factors (15- 25%), can attain positive business cases in Japan if investors carefully fine-tune their projects.



	A	B	C	D	E
Capacity factor	30%	30%	20%	30%	30%
DR	5%	8%	5%	3%	5%
Size-MW	50	50	50	50	100

Project operating results

	A	B	C	D	E	E'	E"
NPV (M$)	223	142	91	299	544	-4	138
IRR	21%	21%	13%	21%	29%	-	13%

Impact of technology | Impact of capacity factor | Impact of DR | Revenues | Direct impact of policies | Positive Levelized GAP | Negative Levelized GAP

(1) Reference wholesale price 2011. Reference spot price 2011

Figure 164. Business cases – On-shore wind in Japan (2012 US$/MWh)

Plants with very poor operating conditions do not result in positive business cases, even at the high FIT levels provided. Decreasing capacity from 30% to 13% increases generation costs by 108%. Therefore, it is very important to ensure that the plants are utilized at a reasonable rate. Other factors are also quite relevant to the definition of an attractive business case. Increasing plant size from 50 MW to 100 MW may lower generation costs by 30-35 US$/MWh. Transmission costs may represent up to 11% of total generation costs.

In summary, from the point of view pure revenue-costs gap, defining a profitable project would be easier in Japan than in other countries with lower incentives. However, the project must be connected to the grid. This may not be as straightforward in Japan as it is in other regions in the scope of this study.

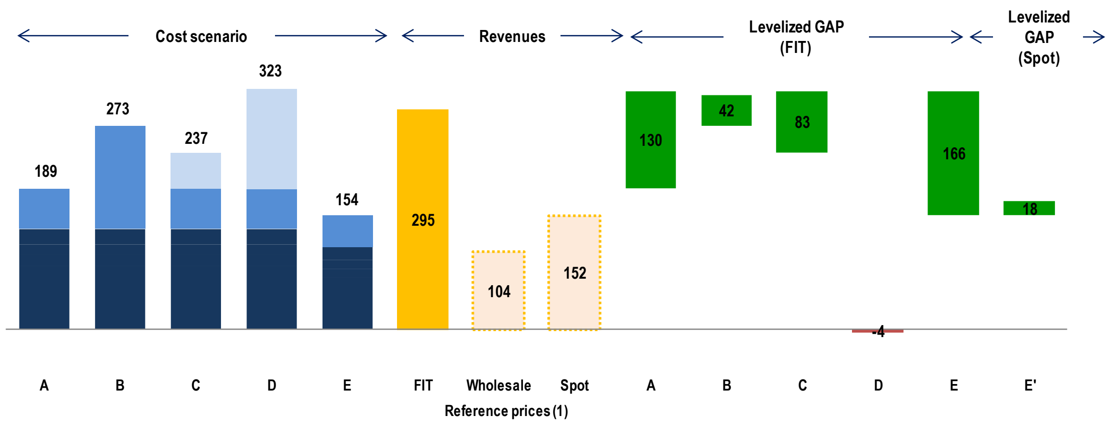
[355] The spot market is very small in Japan. But it provides a transparent reference for electricity prices. Hence the relevance to consider business cases at this level of market prices.

6.9.2 Detailed business cases – Japan / Off-shore wind

Costs of off-shore wind obtained from simulations suggest that projects in Japan are also benefiting from the technical advances in the technology. The costs of the projects included in database of Japan are at similar levels as those of projects in Europe (189-273 US$/MWh)[356]. Access to attractive sources of finance, with lower rates than in other countries, contributes to this outcome.

If the results of the simulations are accurate, the current FIT levels for wind generation would appear to be sufficient to stimulate the development of off-shore wind plants in Japan. The FIT for wind is not adapted to the specific characteristics of off-shore plants. However, the initial levels of the tariffs for wind are so high, that they are able to cover the higher costs of off-shore generation.

With the current scheme, investors in off-shore wind would attain positive income with plants operating in conditions which position them in the medium-low ranges of cost. The current tariff (295 US$/MWh) for wind would result in positive income for good to best-in-class plants: high capacity factors (35-45%), large plant-size (200-600 MW) and discount rates comparable to those of other countries (5-11%).



	A	B	C	D	E
Capacity factor	45%	45%	35%	25%	45%
DR	5%	11%	5%	5%	5%
Size MW	200	200	200	200	600

Project operating results

	A	B	C	D	E	E'
NPV (M$)	956	134	422	-113	3,785	209
IRR	14%	14	10%	-	19%	7%

Impact of technology | Impact of capacity factor | Impact of DR | Revenues | Direct impact of policies | Positive Levelized GAP | Negative Levelized GAP

(1) Reference wholesale price 2011. Reference spot price 2011

Figure 165. Business cases – Off-shore wind in Japan (2012 US$/MWh)

However, recovering the initial investment, and generating reasonable rates of return appear to be more difficult than for on-shore wind plants. This is consistent with the findings in other countries. Realizing profits with an off-shore wind project is not straightforward in any region; and requires specific schemes, adapted to the characteristics of this technology.

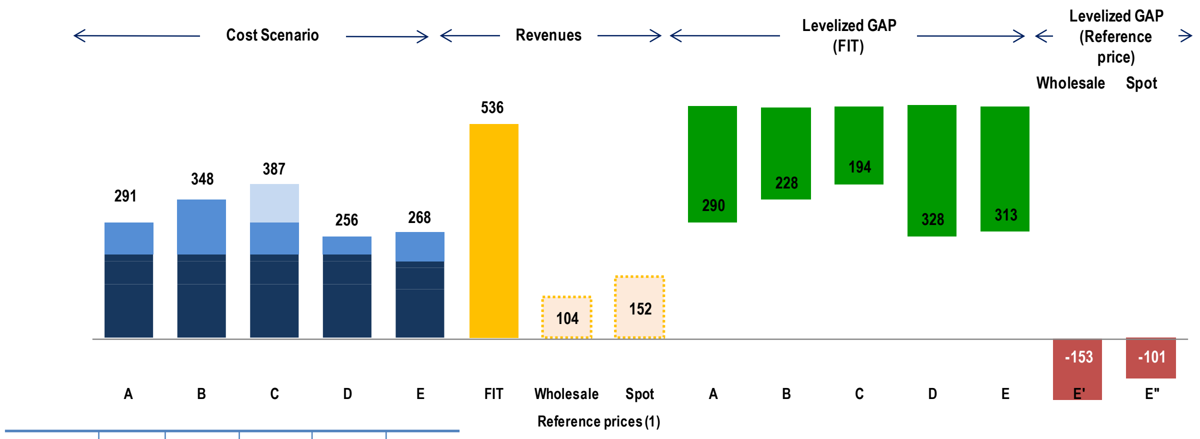
[356] It is not clear that the reported costs include specific characteristics of off-shore wind in Japan such as high costs of construction. The level of precision of existing data does not allow comparing the reported costs of construction in Japan with those of other plants elsewhere.

6.9.3 Detailed business cases – Japan / Solar PV

As it is the case in each of the regions analyzed in the framework of RE-COST, costs of solar-PV Japan are higher than the reference prices of electricity in this country. Therefore, most solar PV plants, even best-in-class (8 -10 MW, 15-20% capacity factor and 3-5% discount rate), would require incentives to deliver attractive business cases to investors.

Simulations show that, with the current tariffs for solar PV in Japan, investments into large solar PV may have attractive business cases, if plants operate in reasonable conditions (15-20% capacity, 283-387 US$/MWh capital costs). The business case would be positive even for smaller plants (1 MW).

Capacity factor has a strong impact on the business case of large solar PV. Decreasing capacity by 5% increases costs of generation by 25-33%.



	A	B	C	D	E
Capacity factor	20%	20%	15%	20%	20%
DR	5%	8%	5%	3%	5%
Size MW	8	8	8	8	10

Project operating results

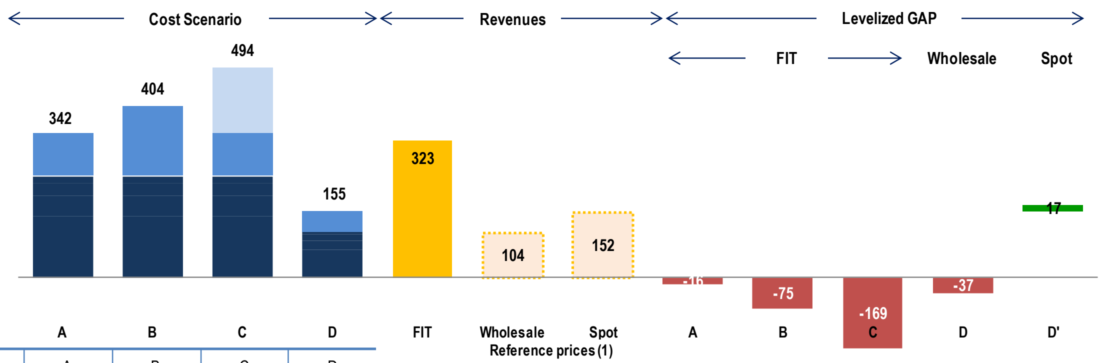
	A	B	C	D	E	E'	E"
NPV (M$)	39	23	18	54	53	-30	-21
IRR	18%	18%	12%	18%	20%	-	-

Impact of technology
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP
(1) Reference wholesale price 2011. Reference spot price 2011

Figure 166. Business cases – Solar PV in Japan (2012 US$/MWh)

6.9.4 Detailed business cases – Japan / Hydro

The simulations of hydro generation (small plants) show very thin business cases, even when considering the relatively high tariff levels awarded to this technology. The costs of hydro generation are significantly high, driven by a combination of high land costs, construction requirements, and other components.



	A	B	C	D
Capacity factor	22%	22%	15%	22%
DR	4%	6%	4%	4%
Size MW	30	30	30	100

Project operating results

	A	B	C	D	D'
NPV (M$)	-36	-65	-111	-129	8
IRR	3%	3%	-	1%	5%

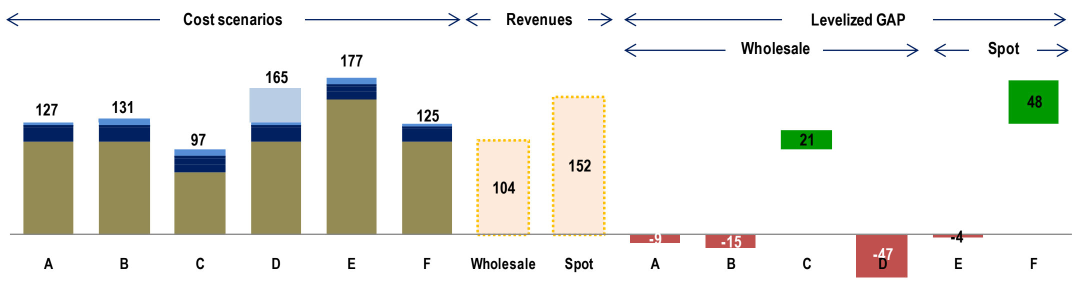
Impact of technology
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP

(1) Reference wholesale price 2011. Reference spot price 2011
(2) FIT only applicable for plants up to 30 MW

Figure 167. Business cases – Hydro in Japan (2012 US$/MWh)

6.9.5 Detailed business cases – Japan /CCGT

Simulations of new CCGT plants in Japan result in relatively poor business cases for this technology, due to the same reasons that have been observed in other regions. Gas-fired plants have experienced a bubble in capital costs in the last three years due to an array of technology, market and supply chain factors, and require high capacity factors to provide good rates of return to investors. However, it is to be noticed that the actual (transfer) prices obtained by gas-fired plants in this country are not publicly available. CCGT plants compensated at higher levels than the 104-152 US$/MWh used in the simulations may actually be profitable.



Reference prices (1)

	A	B	C	D	E	F
Capacity factor	75%	75%	75%	30%	75%	75%
DR	5%	8%	5%	5%	5%	5%
Size MW	500	500	500	500	500	1,200
Fuel Cost	Avg.	Avg.	-30%	Avg.	+50%	Avg.

Project operating results

	A	B	C	D	E	F
NPV (M$)	-444	-504	754	-827	-231	4,444
IRR	-	-	14%	-	-	25%

Impact of technology
Cost of fuel
Impact of capacity factor
Impact of DR
Revenues
Direct impact of policies
Positive Levelized GAP
Negative Levelized GAP

(1) Reference wholesale price 2011. Reference spot price 2011

Figure 168. Business cases – CCGT in Japan (2012 US$/MWh)

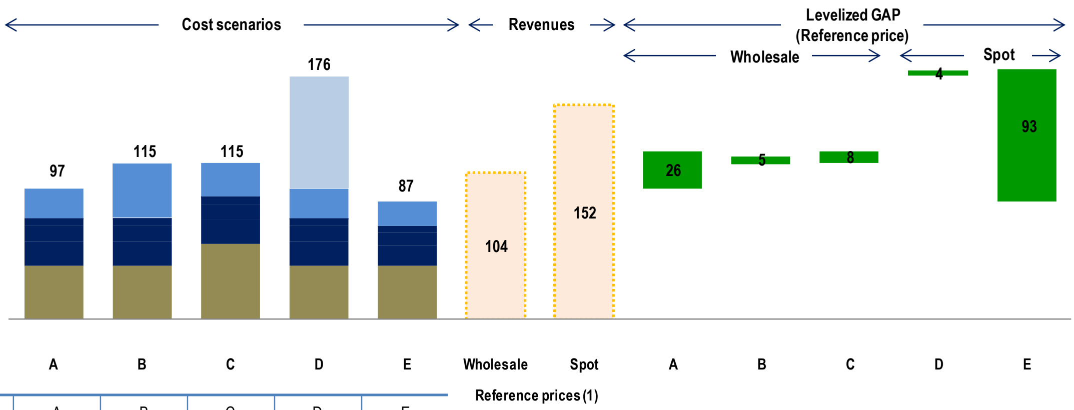
Future market, technology and policy developments may affect this outlook. Capital costs of gas-fired plants are expected to decrease worldwide. Also, increasing focus on emission costs may make coal-fired plants less attractive vis-à-vis gas-fired plants, therewith increasing the average capacity factors of the latter.

It is also to be noted that the prices of fuel (gas and coal) are expected to decrease next year in Japan when/if nuclear generation increases again. This potential development is not reflected in the simulation; but experts interviewed report that the costs of gas plants could drop somewhat in the future, contributing to a decrease in the overall price of gas generation in the country, and to making this technology more attractive to investors.

6.9.6 Detailed business cases – Japan / Coal

New, best-in-class coal-fired plants in Japan show attractive business cases (400-600 MW, 5-8% discount rate and 50-60% capacity factor). The simulations consider relatively small coal plants. They correspond to the data in the database with the highest confidence levels. These plants have 95-120 US$/MWh generation costs. These costs would be below the reference power prices in Japan.

The outcome may be overvalued due to the high capacity factors that some coal-fired plants have had attained in Japan during the time when nuclear generation was practically discontinued. Capacity factors have a large impact on cost of new coal-fired generation. A reduction of 35% in capacity factor would result in 80% increase of the costs of generation.



	A	B	C	D	E
Capacity factor	60%	60%	60%	25%	60%
DR	5%	8%	5%	5%	5%
Size MW	400	400	400	400	800
Fuel Cost	Avg.	Avg.	+50%	Avg.	Avg.

Project operating results

	A	B	E	D	E
NPV (M$)	574	-26	65	-117	4,985
IRR	9%	9%	6%	1%	20%

Figure 169. Business cases – Coal-fired in Japan (2012 US$/MWh)

The results also depend on the prices of coal used. If the price of coal significantly increases, the business case of new coal in Japan may turn to negative. A 50% increase in coal costs would result in 15-20% increase of costs of generation. Finally, higher emission costs would also damage the business cases of some plants.

6.9.7 Japan – Lessons learned

The results of the business cases of new RET in Japan appear to be very attractive. Generous policies result in high margins in simulations. However, high rates may not be the only policy factors necessary to ensure significant and swift development of new RET in Japan. Other measures may be required. For instance, ensuring that independent providers of solar PV or wind generation have unimpeded access to the grids of established suppliers, and ensuring priority feed-in.

However, providing recommendations to improve the structure of the Japanese electricity sector is beyond the scope of this study. Therefore, this section will only focus on exploring which could be the most appropriate tariff levels, in light of the potential costs of generation in Japan of renewable and non-renewable technologies. Insights obtained from the analyses conducted in this study may complement additional assessments focusing on other aspects of the Japanese power sector.

On-shore wind: The current tariff levels appear to be appropriate to generate investors' interest and to ensure significant growth of on-shore wind in Japan. But it may be possible that some plants realize windfall profits with the current scheme. It may be recommendable revising the FIT levels in the future, in order to ensure that the growth objectives of Japanese policy makers are reached, while preventing excessive returns to some investors.

This could be done through two different mechanisms or by the combination of both: (1) adjusting the tariff each year for plants already in operation, as the current tariff scheme proposes or (2) providing a revised initial tariff to plants which will be commissioned in the future. This mechanism may be more advisable because it reduces the risk perception of investors, and stimulates technical and operational improvements.

Any action conductive to modify and adjust the tariffs awarded to on-shore wind should be undertaken only when there is more information about the true costs of generation. That is, when the scheme is older. Providing a scheme based on a tariff degression or on other type of adjustment requires more accurate data than those currently in the public realm. It is highly recommended that Japanese policy makers focus on attaining a very good understanding of the levers that result in apparently higher costs of generation in this country. This will provide them with an essential instrument to optimize tariffs in the future.

Other factors that significantly influence the possibility to bring a plant from project to operation, may be as relevant – or even more significant – as the tariff level itself, in the decision making process of investors. A transparent and streamlined authorization process may have as much relevance as high tariffs. Providing a level playing field favors competition. In a first step, provisions to ensure that independent suppliers connect in optimal conditions to the grid should be strengthened, since this would ensure that all kinds of companies, not only EPCOs, can implement generation projects. In a second step, Japan would need to evaluate how to address and finance an optimization of the national grid, able to support RET developments in an optimal way.

Off-shore wind: Different reasons would support the significant development of off-shore wind in Japan. The lack of land sites, and the availability of areas with suitable wind conditions, make of this technology a good substitute to expand the installed capacity of renewable power (out of sight). Good off-shore wind quality in many areas in Japan may ensure high capacity factors, which will contribute to reduce the unit cost of generation. Significant development of off-shore wind could contribute to increase the independence of electricity supply in Japan. This last factor may be of large relevance for the future electricity policies in the country, in light of the consequences of the Fukushima accident.

There is no specific incentive system for off-shore wind in Japan. Off-shore wind plants are eligible to receive the same incentives as on-shore wind plants. Simulations of the business case of generation for off-shore wind in Japan show that the levels of the current tariffs for wind could be sufficient to provide reasonable margins to investors in this technology. However, access to the grid may not be straightforward for every investor in RET.

If Japanese policy makers desire to further encourage off-shore wind developments, some slight changes to the current policy scheme may be recommendable. In particular, it would be necessary to strengthen the business case of this technology, reducing the perception of risk of off-shore wind projects through a scheme specifically adapted to off-shore wind generation. This could be done by fine-tuning the current tariff to take into account the unique characteristics of off-shore wind. Covering the high capital cost, and providing stable tariff conditions are factors likely to significantly interest investors. Potential actions could include:

- Increasing the initial tariff provided just for off-shore wind. Increasing 5-10% the initial tariff would significantly improve the business cases of this technology.
- Defining a degression of the tariff, as the one in Germany, to balance and adjust the funds provided to the scheme.
- Reducing the opposition of other stakeholders, such as fishermen, by ensuring that they also benefit from the returns generated by the plants.
- It may also be recommendable to be prepared to define lower FIT levels for plants commissioned in the future. However, the information available at the present is not enough to accurately define a specific degression scheme for off-shore wind tariffs in Japan.

Indirect measures of support may also be effective to accelerate cost reductions. For instance, promote R&D projects to reduce capital costs through grants; and engage international project groups to leverage on experiences and to share expenses.

The potential measures discussed above are unlikely to yield significant benefits unless connection to the grid at reasonable costs, and priority feed-in are ensured.

Solar PV: The current tariff scheme for solar PV is based on tariffs high enough to provide good business cases to investors with previous experience in the technology. If connection to the grid is ensured, these incentives may contribute to significantly boost solar PV in Japan. An useful benchmark to consider would be the fast development of solar PV in Spain due to generous initial incentives.

If the current conditions change, the tariff provided might be easily adapted to better reflect technology and operating developments. This would be particularly useful if the significant cost reductions in solar PV, expected in the short term, materialize. When these cost reductions occur, it may be recommendable to revise the solar PV tariff level, to ensure that the growth objectives of the Japanese policy makers are reached, and to simultaneously prevent excessive returns for some investors (avoid windfall profits). This could be done by two different mechanisms, or by the combination of both:

- Adjusting the tariff provided each year to plants already in operation, as the current tariff scheme proposes, or introducing a gradual decrease of the applicable FIT rates[357].
- Providing a revised initial tariff for plants that will be commissioned in the future. This has been done by Germany through the introduction of a degression rate in the incentive scheme which takes into account the cost improvements and developments of new plants. This mechanism may be more advisable because it reduces the risk perception of investors, and provides stable income. Given the expected costs changes in solar PV[358], tariff reductions of 10-20% may be possible in the short to medium term. Also, at some point it may be advisable to decouple the incentives provided to large plants from the incentives provided

[357] On April 2013 the tariff for large solar PV was reduced 10%

[358] Some companies in Europe claim that breakthrough reductions of solar PV costs are already possible. Understanding whether these claims are accurate and whether the proposed reductions are applicable to Japan would contribute to optimize the definition of solar PV policies in the country.

to small plants. This would contribute to better align the incentive levels to the costs of commercially sized solar PV projects (> 2-5 MW), which benefit from economies of scale.

Japanese policy makers should keep abreast of the specific development of large solar PV in Japan to optimize the incentives to this technology in the country.

6.10 Impact of transmission costs in the business cases of generation, and summary of results

The graphs of the region/technology pairs evaluated in the previous pages of this section do not explicitly include transmission costs[359], even though the potential impact of transmission costs has been considered when extracting insights on the business cases of each region/technology pairs. As indicated in section 2.5.8, the actual transmission costs of a given plant depends on a large number of parameters related to the characteristics of the plant, its operating regime, and provisions and country specific regulations. To calculate transmission costs with a similar level of precision as that obtained in the calculation of capital and operating costs, it would be necessary to introduce many more input variables. This may increase the similarities of the methodology used by RE-COST with the approach of investors, but would make it more difficult to extract general conclusions, and to compare the impact of different policies.

Three approaches have been used to assess the impact of transmission costs in the calculations, and to extract conclusions and insights:

- **Do not include them in the calculation**, but assess that the spread revenue-cost is sufficient to cover average costs of transmission.
- **Add average ranges of transmission costs to the calculations** of each business costs, and assess the impact in the results of the business cases of the simulated plants. This method is in line with the overall approach of RE-COST, which uses averages and ranges to compare technologies and countries.
- **Use a separate model** (transmission calculation model) to compute the potential transmission costs associated to different plant configurations (size, load, operating regimes, losses, etc.), and add an average value of transmission during the life of the plant. This last method requires making hypotheses about a large number of operating factors and plant characteristics, and at the end results in levels of precision comparable to the second approach[360]; but it allows computing the business case of a real plant or project, whose characteristics are known.

Figure 170 summarizes the ranges of transmission costs that have been added to the business cases to simulate the potential impact of this element in the decision making processes of investors (same as shown in Figure 33).

	Canada	France	Germany	Norway	Sweden	Spain	Japan
Transmission Cost	5-17	4-14	3-16	4-17	3-10	10-14	10-20

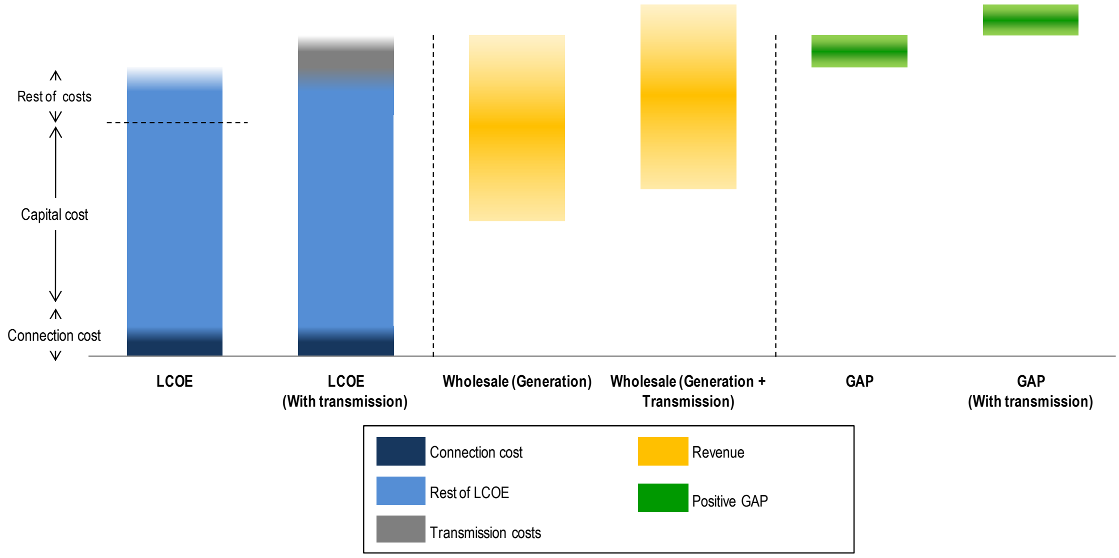
Figure 170. Transmission costs (US$/MWh) – Ranges used in the simulations[361]

[359] Connection costs, also called "first connection" or grid connection costs are included in each of the business cases as a part of the capital costs of the plant, as discussed in section 2.5.2.

[360] The transmission simulation model is not integrated with the RE-COST model. Costs of transmission for a sample of region/technology pairs were calculated and the resulting outputs were added as inputs to RE-COST manually.

[361] Source: Europe: "Overview of transmission tariffs in Europe Synthesis 2012. ENTSO-E". Canada: Hydro-Québec call for tenders. Japan: estimated value through interviews; Prysma analysis.

When including transmission costs in a business case, it is necessary in some cases to consider the potential impact in revenues[362]. The treatment of this additional cost is shown in Figure 171).



Note: Connection cost includes the cost of connection to the grid and upgrading if needed during the construction of the plant. Both costs are assumed by the investor, as a part of capital cost
Transmission cost includes the cost of delivering the electricity from de generation point to the distribution networks.

Figure 171. Example – Impact to the investor of including transmission cost

The resulting summary of business cases is represented in Figure 172.

		On-shore wind	Off-shore wind	Large Solar PV	Hydro	CCGT	Coal
Canada	Alberta	✓				✓	✓
	Ontario	✓ ↔ !		✓ ↔ !	✓	✓	
	Québec	✓			✓		
France		!	✓	✓		!	!
Germany		✓ ↔ !	!	✓ → ✗	✓	!	✓
Norway		✓	✗		✓		
Sweden		✓	✗				
Spain		✓ → ✗		✓ → ✗		✗	!
Japan		✓	✓	✓	!	!	✓

✓ Profitable ! Profitability issues ✗ Not profitable ↔ Uncertain → Impact of policy changes

Region/Technology pairs (scope of analysis) Does not exist or irrelevant Not included in the study

Figure 172. Region technology pairs - Business case simulations [363]

[362] In Germany, the transmission tariff allocated to a given plant may include costs less benefits. That is, costs covered by the tariff are compensated by revenues driven by grid systems (for instance, congestion management). In Quebec, the compensation for generation also includes the costs associated to transmission. In Japan, transmission costs of EPCOs would consist of transfer costs (the utility owns the network), and are eventually passed to consumers.

7. POLICIES IMPACT AND OPTIMIZATION

Insights relevant for the regions and countries in the framework of this study can be translated into general recommendations for policy makers in other countries. This section consolidates a number of lessons learned that may be helpful to review policies and incentives.

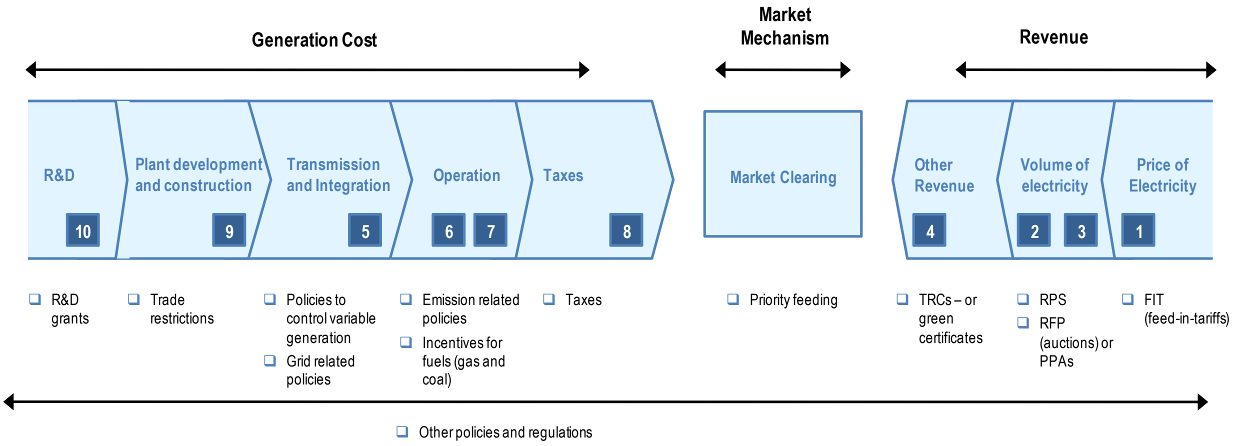


Figure 173. Business case of generation vs. applicable policies

The discussion has been structured using the value chain of electricity generation, a framework that has proven to be helpful to characterize, evaluate, and decide on investments in electricity generation. Figure 173 illustrates the loose correspondence between the components of the business case of generation, and specific types of policies. This framework contributes to focus the next discussions, but it is a simplification. Many policies affect the whole business case of generation, either directly or indirectly. In addition, interactions between policies may have unexpected results, either positive or negative. This has to be kept in mind when attempting to optimize policies in the power generation sector.

7.1 Price incentives – Feed-in-tariffs (FIT)

A feed-in-tariff is an electricity regulation, decree or normative that defines terms and conditions for the sale of electricity that provide an advantage to producers[364]. There is a large variety of definitions of FIT. Usually policies based on FIT require utilities or other parties to purchase certain amounts of electricity, or electricity and electricity attributes[365] from eligible generation plants at prices that, in the majority of the cases, are higher than the prices the plant would obtain without the tariff.

The general opinion of the market, confirmed by the interviews with market actors is that FITs have been and continue to be a very important factor in the development of new renewable generation technologies worldwide. Also, the analysis conducted in the framework of this study show that the sudden interruption of FIT in the

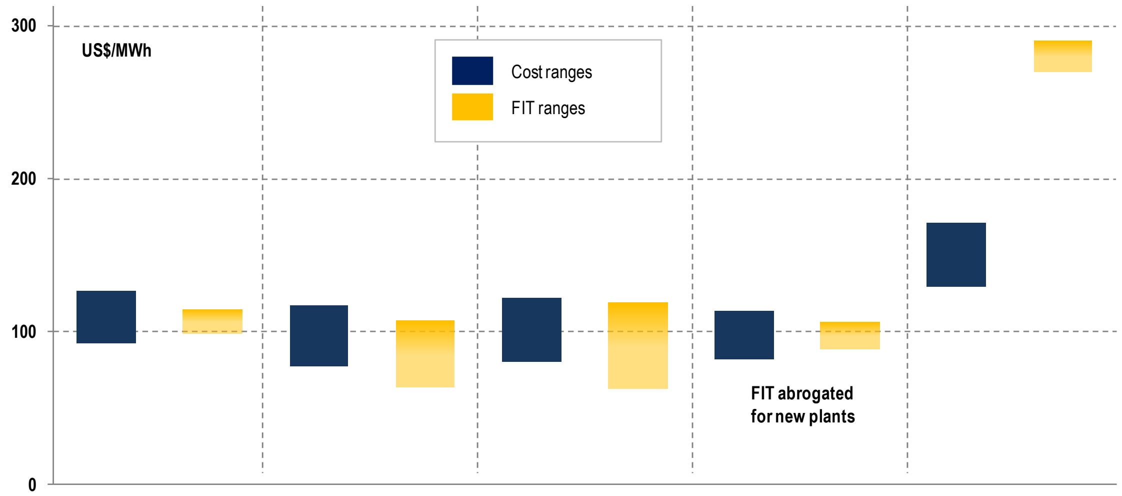
[363] Include direct incentives and policy support

[364] Source: NREL. Feed-in-Tariff Policy: Design, Implementation and Policy Interactions – March 2009

[365] In the U.S. FITs in some states require to also purchase attributes. In Europe, Canada and Japan FIT usually focus on the purchase of electricity.

countries where they exist is likely to result in a moratorium of new generation developments. One example is Spain (see Section 6.8) where, since the FIT for on-shore wind and solar PV were suspended at the beginning of 2012, very few new projects have been launched.

Figure 174 displays examples of wind projects in different countries with a FIT scheme (currently applicable to new developments), or past FIT (applicable to projects already commissioned).



	Canada - Ontario	France	Germany	Spain	Japan
Capacity factor	30%	30%	30%	30%	30%
DR max	8%	10%	10%	8%	12%
DR min	3%	3%	3%	3%	6%
Gross MW	100	50	50	50	50

Figure 174. Impact of FIT on on-shore wind projects (US$/MWh)

Lessons learned to optimize the design and implementation of feed-in-tariffs include:

Continue providing FITs in those circumstances where they are required, for instance in France, Germany, Ontario or Japan. Simulations of the business cases of RET (wind and solar PV) show that, in spite of significant reductions of costs effected by these technologies, average projects are still unprofitable unless additional support is provided. Blanket statements about short term elimination of tariffs should be avoided, since they increase the perception of country and technology risk.

Continuously revise the FIT levels and conditions and use tailored approaches to define them. In general, a FIT that specifies more parameters and conditions of applicability may be tailored more specifically to the required objectives of policy makers, if it is well defined (France and Germany). Best practices include FITs that consider technology evolution and trends to entice investors in projects situated in the low ranges of cost. For instance, projects in sites with better wind quality should have priority over projects in sites with less wind quality.

In general, the revision of the FIT should not include retroactive provisions, since this can also increase the perception of risk.

Adapt FIT degression levels to realistic potential reductions of cost. Several countries in the scope of the study have defined FIT schemes where the FIT levels drop over time. These schemes potentially adapt compensation levels to the evolving costs of generation, and gradually wean the affected technology off incentives. Insights from the simulations carried out in the framework of this analysis include:

- Awarding to a plant a FIT that degrades over time – whose value is specifically defined to wind down, or whose value is not adapted to inflation and growth of factor costs – may put excessive hardship on investors (e.g., on wind and solar PV producers).
- Degressing the initial FIT over time may provide better results for policy makers and for developers. Progressively lower tariffs select plants that incorporate lower costs technologies, gradually reducing the levels of necessary incentives. This forces developers to innovate, and provides them with clear benchmarks they have to reach.

Obtain more accurate data: include in the FIT conditions, provisions to disclose plant data, in order to increase the information available to policy makers regarding the actual costs and returns of the beneficiaries of policies. This will also require to fund and communicate original and tailored studies that evaluate the effectiveness of FIT and of interactions of FIT with other policies. These studies should be based on a statistically significant list of historical and current data of generation plants that have benefited from the FIT in a given region (local, national). The cost of the analyses is likely to be a very small fraction of the total funds paid through FITs.

Put a cap on the funds allocated to the FIT, both to the total funds provided in the framework of the incentive, and to the funds allocated to a given plant. This measure should help to prevent windfall profits for some investors, while simultaneously providing a sense of controllability of the FIT and of its associated expenditures.

Allow improvements in the costs of the plants to be introduced by developers and owners, to incentivize existing plants to incorporate new solutions that contribute to making the technology in question more efficient and therefore to make the tariff redundant in a shorter time frame, rather than in the long term. In particular, repowered plants should be still eligible to receive the FIT.

It may be argued that some of these recommendations could be applicable to any type of incentive. However, FIT are a very visible part of the policies for RET deployment. Optimizing FIT and other revenue mechanisms discussed later in this section are some of the most effective ways to optimize incentives to generation technologies.

7.2 Incentives focusing on electricity volumes – RPS[366]

Policies and regulations also influence the volumes of electricity that a producer sells to the market through two main mechanisms:

1. Indirectly: allowing some technologies and plants to participate in the market. In a strict sense, all the policies that incentivize a technology or plant have impact the volumes of electricity sold, not only by the plants directly targeted by the policy, but also by the rest of the plants operating in the market. Incentivizing on-shore wind affects the capacity factors of coal-fired plants, and vice-versa.

2. Directly: establishing the obligation of purchase of given volumes of electricity generated by eligible providers, under a set of given conditions. A variety of policies have been established to influence the volumes of electricity supplied by different technologies of generation (mostly RET).

- **Priority feed-in policies** – to ensure that some technologies are fed first to the grid. The volume of electricity depends on the possibilities of the plant, and the will of the producer. For example, a supplier may choose not to sell an amount of power if the price of the electricity at that moment is lower than the variable cost of generation.

[366] Other denominations of RPS are “quota based mechanisms”, “quota obligations” or “renewable obligations

- **Pure RPS: Renewable Portfolio Standards**. These policies compel suppliers of electricity to provide a given proportion of energy generated through green technologies, or establish which proportion of the total demand has to be covered by renewable technologies. The market defines the price of the renewable obligations because no tariff is defined. This type of policies is used in Japan (formerly), Sweden, Norway, and in some provinces of Canada.
- **Competitive solicitations**[367] define the amount of electricity to be provided by the producers who respond to the solicitation. The price of electricity is decided through a bidding process[368]. Some of them also provide a range of acceptable prices to enhance, and better control, the results of the solicitation. Examples are the on-shore wind solicitations in Quebec, and off-shore wind and solar PV solicitations in France, discussed in Sections 6.4.1 and 6.5.2 respectively. At given levels of demand, introducing additional volumes generated by a given technology reduces the electricity volumes generated by other technologies, if there is a purchase obligation.

Recommendations to optimize the definition and results of auctions would include:

Consider auctions as interesting mechanisms to ensure the deployment of a technology when the market prices alone, or the market plus other incentives are not enough, and it is necessary (and possible) to control or optimize a number of aspects of the projects.

Make public the results and conditions of the winners of the auctions. Not only to increase the transparency of centrally directed schemes, but also to raise the interest of additional suppliers, who may want to participate in the next one, if the conditions are interesting enough.

7.3 Additional sources of revenue – TRCs – Green certificates

In addition to selling the power generated, producers may sell the attributes of the electricity produced. One of the most widespread attributes is TRCs –Tradable Renewable Certificates[369]. A TRC represents the attributes of 1 MWh of (renewable, low emission) electricity. The attributes may be sold either in combination with the electricity they represent, or separated as independent products[370]. TRCs may be used to integrate renewable generation technologies into the wholesale utility markets, and to meet and verify renewable policy goals. Producers of eligible RET may increase their revenues by trading with TRCs.

Regions where different TRC schemes have been, or are still, defined include the U.S., the EU, and Australia. One of the most interesting TRC schemes is the joint **el-certificate system** defined by Sweden and Norway (see Section 6.7 for further information).

Recommendations for the optimal development of TRCs in general and green certificates in particular would include:

Define sophisticated evaluation models that are updated overtime: To define and establish optimal REC systems, it may be necessary to use more sophisticated models than those necessary to define other support schemes; especially if they apply to different environments, and more than one country. The interaction of the market

[367] Also denominated RPS, PPAs, and auctions

[368] Bid prices, as well as potential participants in the auctions are usually subject to conditions and limits: RFPs tend to include a significant number of limits, boundaries, and levers to ensure that the offers selected confirm with the desires of the organizer of the RFP.

[369] Source: Clean Power markets: www.cleanpowermarkets.com - accessed in November 2012

[370] TRCs are also denominated Green tickets or green tags or green certificates, RECs (Renewable Electricity Certificates), Renewable Energy Credits, RRCs (Renewable Resource Credits), T-RECs (Tradable Renewable Energy Credits / Certificates), etc.

behavior of the two components of the scheme adds complexity to the evaluation and forecast of the behavior of the certificates. As a consequence, joint schemes may not be accurately modeled with simple models, and may require utility type calculation models. For example, preliminary results for on-shore wind in Norway and Sweden suggest that a thorough analysis has been conducted prior to launching the el-certificate system.

Develop hand-on expertise with joint schemes. The joint certificate system for Norway and Sweden is the first of its kind. It provides the electricity sector worldwide with an excellent occasion to evaluate the behavior of a carefully thought incentive. Analyses of the results and level of success of the green certificate system are likely to contribute to the improvement of other, similar systems.

Homogenize the conditions of the participants in joint schemes: Joint schemes appear to be easier to define if participants have similar characteristics. The concerns that are being voiced in Norway and Sweden – countries with many similarities in their generation basis, markets and political systems – are likely to multiply when trying to define joint schemes that involve countries with more differences.

7.4 Policies to manage and control variable generation (intermittency)

New RET (solar PV and wind) are intermittent; they may not be available when needed. In addition, they are non-dispatchable; their output cannot be easily increased or decreased in real time to meet variable demand.

Policies that stimulate new RET generation incentivize and prioritize electricity with variable, non dispatchable characteristics, over power generated by dispatchable technologies, such as hydro, gas or coal. These decisions are very visible, and result in additional costs to the electric system. Therefore, they may become the object of discussion and criticism. It is worthwhile to address this aspect when discussing tools to optimize policies, especially in regions where the penetration of variable generation technologies is significant.

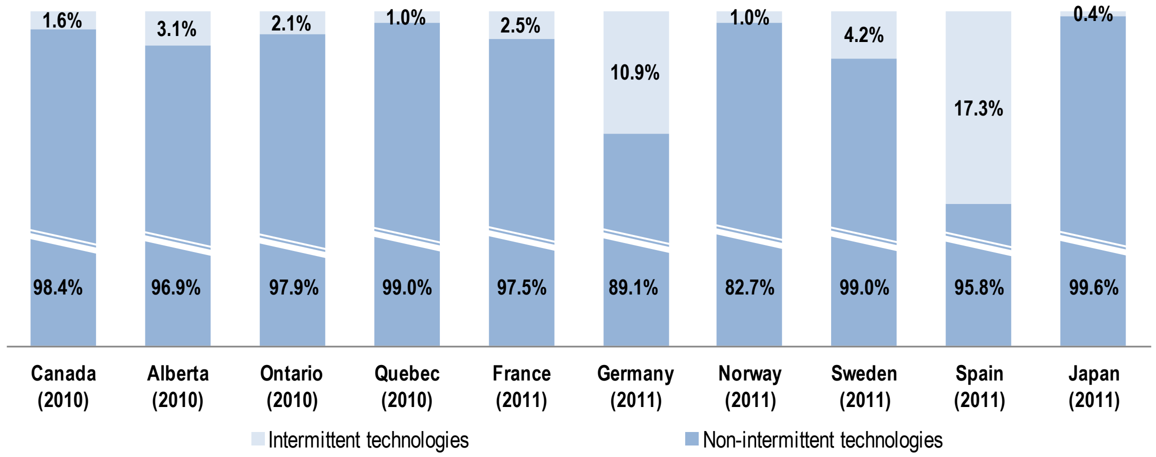


Figure 175. Penetration of wind and solar energy in electricity generation – 2011[371]

In the countries in scope of RE-COST and in many other regions, TSOs, distribution companies, and regulators have designed transmission systems able to operate with high levels of reliability in environments with growing amounts of variable generation. One example is Spain, a country with a large proportion of RET installed capacity (average 24.1% in 2011[372]) and priority feed-in of wind and solar electricity, resulting in a rather high percentage of

[371] Source: PRYSMA analysis

[372] Source: REE

intermittent production (average 17.3% in 2011[373], but with some record days in which 50%[374] of the total electricity consumed was generated by wind and solar plants). The main issue is that the details of these control mechanisms are not usually made public, with the necessary level of detail to allow public discussions and evaluation of the costs associated to them.

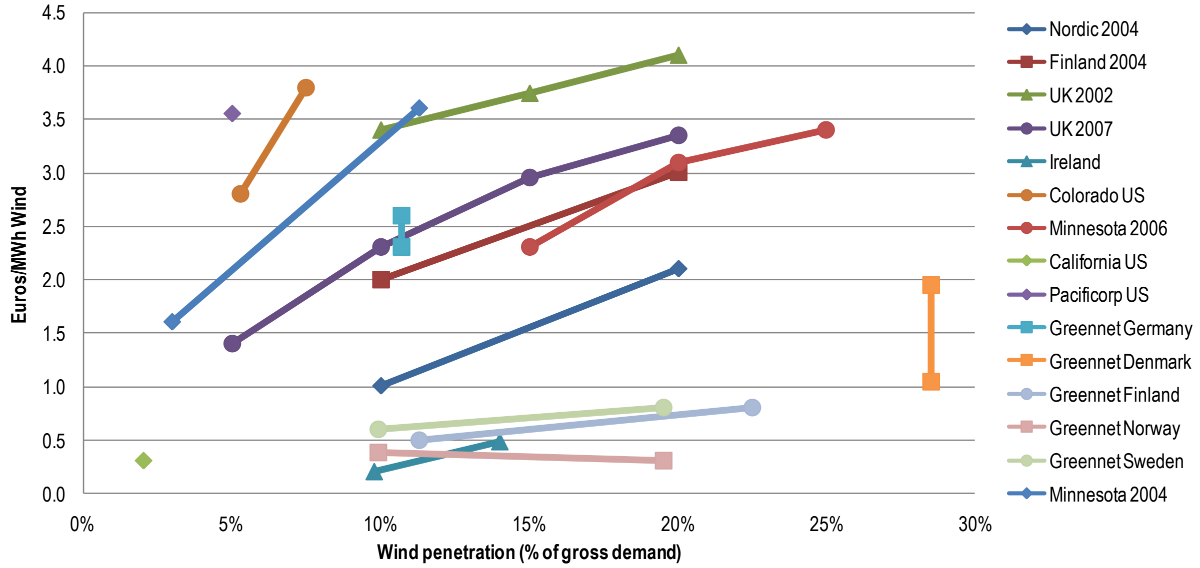


Figure 176. Estimates of increase in balancing costs due to wind variability (€/MWh)[375] .

In addition, integration costs are very difficult to calculate accurately. Estimating a theoretical baseline scenario without variable generation is rather complex, because of the many interactions between the components of the power system[376]. Plants based on traditional generation technologies can also create integration costs in the system[377]. Figure 176 shows an example of estimates of balancing costs that consolidates the results from different studies.

In most countries, most of the network costs are borne by the grid owners, which pass them on to consumers, tax payers, or to other stakeholders. But a portion of the costs is charged to producers of electricity. Some investors in dispatchable plants claim they are compelled to maintain balancing capacity that does not cover their costs, while their business is being hit by low capacity levels due to the competition of new RET. They assert that the combined effect of these two factors is not compensated by the sale of balancing electricity. It is difficult to determine the

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[373] Source: REE

[374] Source: November 8th, 2009. www.carboncommentary.com/2009/11/15/853

[375] Source: IEA-NEA - Projected costs of generating electricity 2010 edition with data from IEA Wind 2009. Estimates significantly differ by country (are very low for the Nordic countries due to the large amount of dispatchable hydro in their system), and by methodology used. Also, they do not contemplate wind penetration rates greater than 30%. If results from studies do reflect reality, it would seem that total costs of balancing the system are lower than 5%

[376] Source: NREL - Cost-Causation and Integration Cost Analysis for Variable Generation – June 2011

"To date no really satisfactory proxy resource has been found. The current status of VG integration modeling is:

- *There is no universal agreement on methods for calculating renewables' integration costs, and even when there is agreement on methods, they are not consistently applied or are applied with errors.*
- *There are many potential base-cases (no-wind-or-solar) that may be relevant for comparison.*
- *High penetrations of wind and solar impact the optimal mix of conventional generation, further complicating the base-case selection.*
- *There is general agreement that wind [and solar] have an impact on operations, but there is substantial disagreement about whether/how integration costs can be measured"*

[377] Source: Ibid

accuracy of these allegations. However, this situation clearly needs to be addressed by policy makers. It would be necessary to define policies where the rules not only are fair, but they are perceived and agreed as such by most of the participants in the electricity sector.

Recommendations to control and manage the variability introduced by some RET may include:

- As penetration of variable generation sources increases, **policies to foster and develop RETs have to become much more holistic**. It is necessary to contemplate their impact of the whole electricity sector of a region. It is also essential to consider both the primary and secondary impacts of policies affecting power generation.
- The current initiatives to strengthen the transmission grids are likely to contribute to mitigating the impact of variable generation, and to increasing the reliability of the network. Since grid owners have the knowledge and capabilities necessary to evaluate the real cost impact of variations, it would be advisable that they **commit to the publication of their detailed analysis and results in the public realm.**

In light of the lack of accurate information, it is not possible in the framework of this study to suggest who should pay for the impact of variable generation in the electric system. However, this is an issue whose importance is going to grow over time given the large targets of intermittent RET generation that have been proposed for 2030, and 2050. **Being prepared to answer these questions with hard data and facts** will significantly contribute to the effectiveness and credibility of policies that stimulate new RET.

7.5 Emission related policies

Another policy driven mechanism that affects electricity generation is emission costs. Policy makers use this factor as a tool to curtail emissions and to evolve towards emission mitigation targets. Policies put a price on greenhouse emissions. A portion or the totality of this price must be paid by polluting energy sources. As a consequence, investors in coal and gas-fired plants have to include the costs of emissions in their business cases. There are two main mechanisms to define the price of carbon emissions:

- **Carbon taxes** – Carbon taxes can have a direct effect on the cost of electricity: when producers of electricity are taxed according to the level of emission they produce. Carbon taxes can also have an indirect effect, when they increase the price of the factor costs of electricity generation[378].
- **Cap-and-trade systems.** Administrations define a maximum (the cap) for total emissions. Emitters have to buy allowances for every extra ton of emissions they generate over the cap. Three factors determine how effective carbon policies are in curtailing emissions, and how much they ultimately affect the prices of generation (1) the fine for surpassing the allotting emissions, (2) the price of emissions, and (3) the applicability rules of the system.

Defining additional policies may not be as effective as **fine-tuning and applying existing schemes.**

- **Consider all the policies that affect generation in a comprehensive way,** evaluating the instances in which two current policies may have opposite effects. For instance, in European countries, FIT designed to foster and support RET installation coexist with high allowances to coal-fired plants. Although policy makers may be trying to be fair to all kinds of generation technologies, it would seem more appropriate to fine-tune one policy that supports the development of RET, than to create two policies with opposite effects.

[378] Several incentives schemes in the countries in the scope of this analysis have already considered this potential effect. For instance, carbon taxes are not applicable to factor costs of electricity generation in Sweden

- The alignment of policies has to be carried out not only at the national level, but at the **supranational level** in the case of Europe, or **supra-regional** level in Canada. Defining joint policies is difficult, as illustrated by the challenges posed by the definition of el-certificates by Norway and Sweden. However, given the increased integration of electric systems and markets, it is necessary to define common policies for carbon pricing and emissions abatement, always considering that this should not hinder front-runners to do more than others.

Consider the evaluation of a **life cycle approach to emission abatement.** Most of the policies to reduce emissions electricity generation focus on operating phase of the plant. To take into account all the sources of emissions, and to reduce leakage, it would be recommendable to introduce an evaluation of the emissions of generation plants from the cradle to the grave. Using a life-cycle approach to emission calculation is not an easy task. However, in the mid-term this would not be excessively complicated, since calculation tools exist, and many companies already evaluate their emission levels by product or service. Figure 177 shows and analysis of life-cycle GHG emissions for power plants.

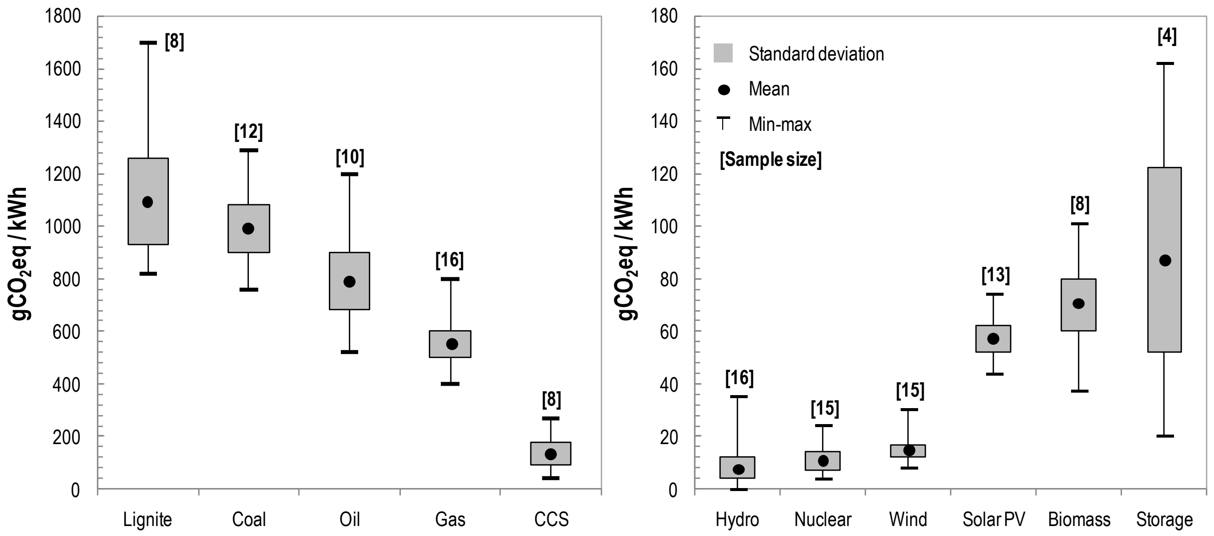


Figure 177. Summary of life-cycle GHG emissions for selected power plants[379]

7.6 Tax incentives

Taxes can be powerful tools to encourage and reward generation plants, or vice-versa, to discourage investments. A number of mechanisms affect the taxes assessed to a generation project:

- **Rebates or exemptions** or royalties, sales taxes, producer's levies and taxes, which that reduce the total tax amount that has to be paid by producers of electricity.
- **Tax credits.** Examples include the provisions that allow applying negative taxes from a project to other projects, or from a year to subsequent years.
- **Accelerated depreciation allowances**, which reduce the income of the plant, resulting in a lower tax base in the first years after plant commissioning.

The recommendations to optimize the tax system applicable to power generation would be very similar to that of other incentives that affect factor costs:

[379] Source: (Weisser) – A guide to life-cycle greenhouse gas (GHG) e missions from electric supply technologies - 2006

- **Make them visible.** Tax schemes are notoriously difficult to assess, because of the large number of specific stipulations that affect the electricity sector, and the large variations of tax provisions from one plant to another. In addition, the specific taxes paid by a given plant are not public. This contrast with the detailed and extensive information that exists about the support provided to RET plants in the form of revenue or volume incentives. It would be recommendable that policy makers make an effort to gather and codify, with the same level of accuracy and depth as they devote to codify FIT or RPS schemes, the incentives (in particular taxes) applicable to other forms of generation. A more complete picture of the actual systemic costs of all types of technologies may emerge.
- **Fine-tune them**. The large amount of tax provisions makes it likely that some of them will overlap, and that others will provide loopholes to participants. It may be recommendable to conduct a careful evaluation of the direct and indirect impact of taxes on the generation basis of a region, in order to fully gauge their actual effectiveness. Again, very few reports and studies exists in this area.

Of particular relevance is to **ensure that taxes do not interact with other policies in unexpected ways**. In particular, reducing the viability of some projects to which incentives are being provided (for instance, providing FIT to RET and tax exemptions to other technologies).

7.7 Trade restrictions

Trade restrictions modify or hamper in some way the free trade of products. Examples of trade restrictions in energy generation include: barriers to the (perceived or real) dumping of plant components, local content provisions, barriers to the introduction of products, etc. Examples of trade barriers that affect the countries in scope of this study include the requirements for local content in some RPS in Quebec and the recently (2013) proposed increase on taxes for Chinese suppliers of solar PV modules.

Trade barriers may have a beneficial impact on some aspects of the economy of a region. For instance, they may contribute to stimulate some regions or some productive sectors. But they also may increase the costs of generation through several mechanisms: by increasing the prices of materials and labor associated to a generation plant and through them, the cost of generation; by eliminating suppliers with potentially lower costs, creating enterprise clusters that may be disadvantaged when competing in the global market; etc.

Developing policies that reduce or mitigate trade barriers in the long term may be beneficial for the electricity sector. Examples include creating integrated markets, monitoring and reducing existing trade barriers, and defining policies that penalize countries that establish excessive trade barriers.

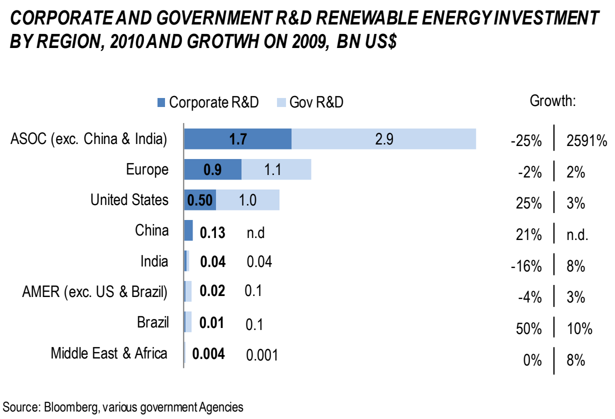
7.8 Grants: incentives to R&D

One extended mechanism to develop and support generation is to provide grants to specific activities, companies, products, etc. R&D grants are some of the mechanisms by which public administrations have contributed to the development of new technologies such as wind, solar PV, etc. Savings in R&D costs may translate into lower product costs, or into earlier market entrance. Tracking down the specific impact on generation costs of an R&D grant is not easy; but it is important to devote some thought to this aspect, and to try to assess orders of magnitude of total expenditures, for a number of reasons:

- The **sheer size of R&D** for electricity generation, both for renewable and non-renewable sources, in developed countries; and its impact on the costs of electricity (R&D costs for RET amounted to US$9,000 M in 2010). It is estimated that in 2010, for the first time government spending as green stimulus packages has overtaken company spending in R&D for renewable energies[380]. A comprehensive evaluation of the impact of policies in electricity generation has to contemplate this point.

- The **significance of R&D for some of the technologies** in the scope of this report, for instance, wind, and in particular off-shore wind. There is a major R&D focus to stimulate the development of wind generation off-shore, where the wind blows harder and at more continuous rates. It may be worthwhile to explore how R&D costs may be built into the costs of new projects, and how these costs may change in the future.
- **A significant number of incentives** in the countries in scope refer to R&D and innovation grants in the electricity sector. It is necessary to have a good picture of the current situation to be able to provide useful policy recommendations.

The graph below shows a summary of recent R&D expenditures in renewable technologies.



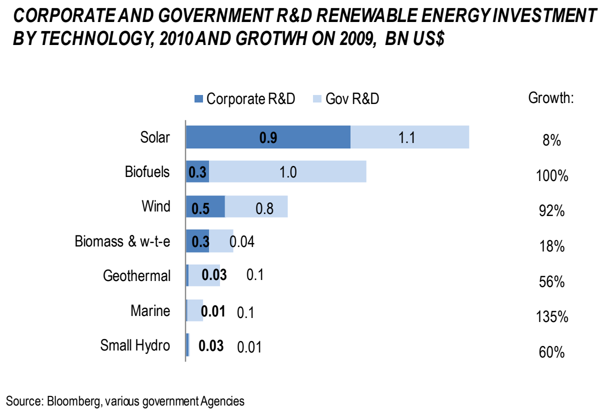


Figure 178. Corporate and government R&D investments in renewable technologies[381]

Lessons learned for policy makers would include:

- Restrict R&D grants to **new technologies,** not to improvements of mature technologies. Commercial companies are better positioned to understand the market value of upgrading a component or a process in a generation plant. If the improvement is cost effective, they will implement it with their own funds.
- Restrict R&D grants to **recognized parties,** who actually do R&D that may result in a commercial improvement at some point in the future. In the last years, large amount of funds have been provided to innovation, technology, and other R&D projects in the electricity sector. Experience shows that some of these funds may end up supporting products and services that never had a chance of attaining commercial value.
- Make grants related to electricity generation **technology specific** (to the extent possible), so they are more easy to track and evaluate.

Periodically (annually at least) **perform an analysis of the impact** that cumulative R&D funds have had on the specific targets for which they were developed.

[380] Source: Global trends in renewable Energy Investment (2012) – Bloomberg

[381] Global trends in renewable Energy Investment (2012) – Bloomberg, Prysma analysis

PART 3

8. METHODOLOGICAL ELEMENTS

RE-COST heavily relies on the identification, analysis and quantification of the factors and elements that define the business case of new power generation plants and projects. These include plants that have been commissioned in the recent past (3-4 years), and generation projects expected to start operation in the near future (2-3 years).

Specific characteristics of the methodology used in the study include:

- **Refers to specific countries and regions**. The analysis focuses on specific countries. This provides the reader with a concrete view of the different regulations and policies that have been deployed in each region, how these policies influence RET deployment, and how they may affect the business case of generation of new plants and projects.
- **Based on data from real plants and projects**. Analyses rely on a comprehensive database which includes more than 120 plants and projects. The bulk of the data has been provided by actors in the electricity sector including utilities, investors, developers, and manufacturers. In a few cases, primary data have been complemented with information from publications. This approach ensures the novelty and immediacy of the information.

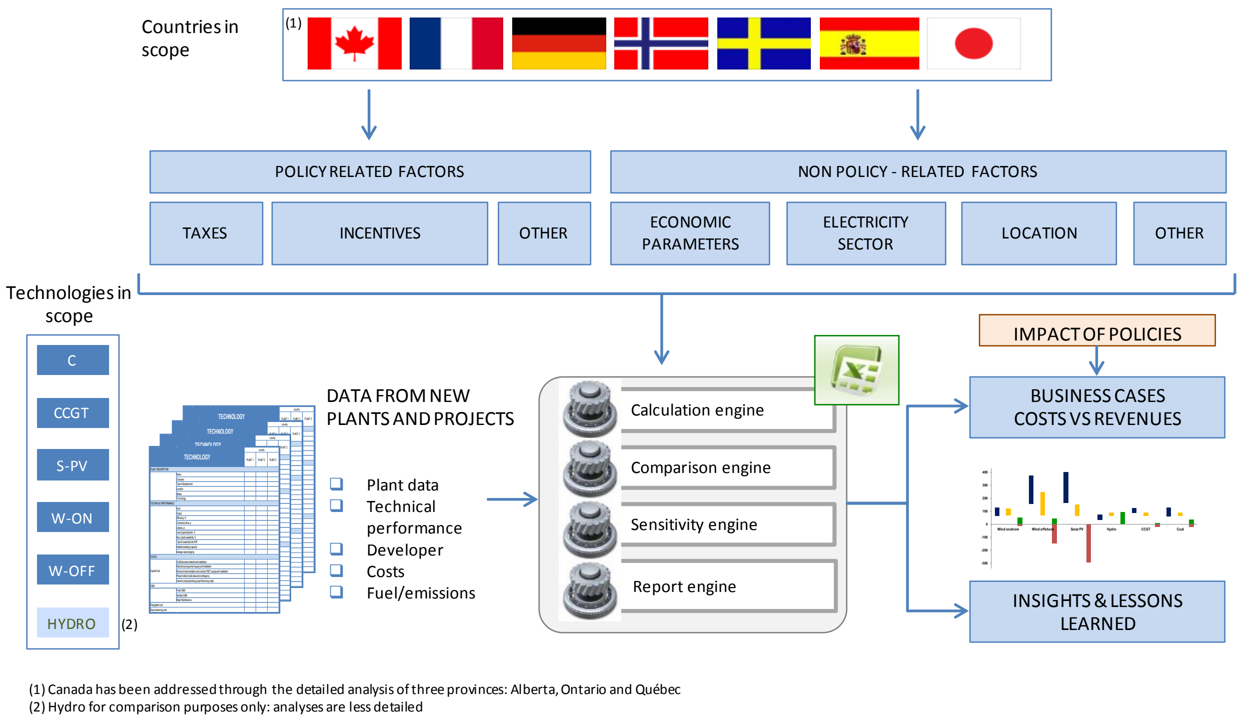


Figure 179. RE-COST – Methodological elements and analysis engine

- **Considers business cases**: The study focuses on the evaluation of the business case of generation plants and projects. That is, it contemplates not only costs of generation, but also potential revenues, margins and returns of investment.
- **Relies on an analytical engine:** RE-COST uses an analytical model that has been specifically built to support this study, and that has been programmed to test the impact on the business case of generation of a large number of elements, including technical factors, country characteristics and policies. More than 1,200 simulations have been conducted to evaluate and explain how changes a large number of variables may affect investment decisions.

- **Includes insights from actors in the power sector:** Hard, quantitative data and information have been enriched with insights from an extensive number of interviews with industry actors. Interviews have been particularly useful to gather insights from the individuals who make and influence investment decisions, as well as to discuss the impact of policies and regulations over the business cases of specific generation projects.

8.1 Scope of work

Figure 180 illustrates the scope and level of depth reached in the analysis of region /technology pairs in RE-COST.

The study focuses on seven countries in three continents: Canada, France, Germany, Norway, Sweden, Spain and Japan. The analysis of Canada centers on three of its largest provinces: Alberta, Ontario and Quebec.

		Wind on-shore	Wind Off-shore	Solar PV	Hydro[382]	CCGT	Coal
Canada	Alberta[383]	√	–	–	Approx.	√*	√*
	Ontario[384]	√	–	√*	√*	√*	–
	Quebec[385]	√	–	–	√*	–	–
France[386]		√	√*	√	Approx.	√	√
Germany[387]		√	√*	√	√*	√	√
Norway[388]		√	√*	–	√*	–	–
Sweden		√*	√*	–	Approx.	–	–
Spain[389]		√	–	√	Approx.	√	√
Japan[390]		√*	√*	√*	√*	√*	√*

√	Complete BC[391] evaluated. Only real plants	√*	Complete BC Real plants + publications
Approx.	Approximations. Only evaluation of costs	-	Not included in the study

Figure 180. Region / technology pairs in scope

382 Hydro is considered only as a reference, given the importance that hydro generation has in some of the regions in scope. Data and analysis have a lower level of detail than those of other technologies.

383 Alberta does not have off-shore, solar PV (commercial), and nuclear plants.

384 Ontario has decided to shelve the first proposed Canadian off-shore wind farm; and it is planning to phase out coal by 2014.

385 No off-shore wind or solar PV (commercial), or CCGT or coal-fired plants or projects appear in the plans of Québec. The only nuclear plant in the province was decommissioned on December 28, 2012 (source: Hydro-Québec).

386 France's generation mix includes all technologies.

387 Germany has announced its intention to transition out of nuclear generation by the year 2022.

388 Nuclear, coal and large-scale solar PV plants are not considered relevant for Norway. There are only 3 CCGT plants in the country, and it does not appear there are plans to build a new one in the short term.

389 No off-shore projects exist in Spain. It is unlikely that any farms will be built in the medium term.

390 Japan's energy mix includes all the technologies in the scope of the study.

391 BC = Business case

The technologies in the scope of the study are on-shore wind, off-shore wind, large solar PV[392], coal (supercritical technology with pulverized coal), and gas (combined cycle generation technology - CCGT[393]). Only utility sized (large plants) generation is considered. Domestic wind and roof-top solar are excluded from the analysis. Hydro has been added as a reference, given the relevance of that this technology has in some of the regions in the scope of the study.

8.2 Business cases assessment – Methodology

The business cases presented consist of simulations of the financial results that a set of theoretical plants would achieve if they operated in a range of conditions.

The technical and operating characteristics of each of the theoretical plants are calculated through regression curves based on the database of real plants and projects gathered for this study. The regression analysis yields estimates of the components of cost of each region/technology pair, as a function of the size of the plant, as shown in the figure below. (Point A, in Figure 181)

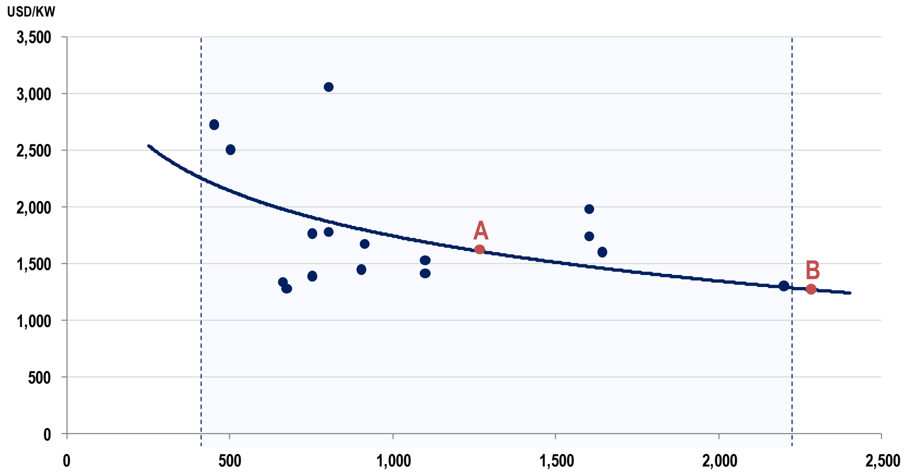


Figure 181. Example of regression to calculate the characteristics of a simulated plant

To ensure that the results of the analyses truly represent the behavior of new plants, an extensive number of sensitivity analysis have been conducted, evaluating the impact of the variations of a number of key parameters over generation costs and revenues.

- **Plant size:** Larger plants tend to have lower unit costs due to economies of scale. For each business case at least 2 relevant plant sizes have been considered. In some cases, the plants sizes considered were beyond the ranges of the available datasets (point B in Figure 181). This significantly expands the breath of analysis and improves the quality of comparisons between technologies.
- **Discount rates:** Financing ratios significantly influence the costs of generation of any technology, renewable and non-renewable, and enable to understand the potential impact of different levels of risk in the business case of a given plant.
- **Capacity factors:** As it is extensively discussed in several sections of this report, the capacity factor of a plant significantly affects the unit costs of generation, and therefore the resulting business case for potential investors. In order to ground the analysis on the reality of each region/technology pair,

[392] The study refers always to utility-scale (> 1 MW) solar PV if not otherwise indicated.

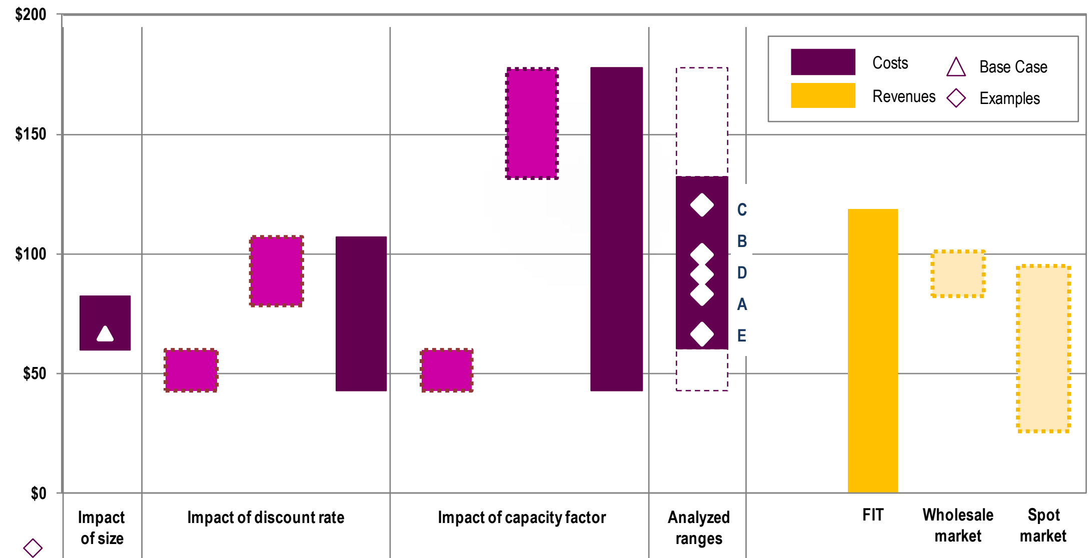
[393] The study uses the terms CCGT and gas-fired indistinctly

ranges of capacity factors have been used in the simulations, taking as a reference two values: the engineering or design capacity factor typical of each generation technology, and a reference capacity factor calculated as the average of capacity in year 2011 of each region/technology pair. (See Figure 43)

- **Fuel costs:** For gas-fired and coal-fired plants, the impact of variations of the price of fuel have also been included.

- **Transmission costs:** average costs of ranges are usually added to the calculated costs of generation to identify the impact of these costs in the business cases of investors, or investors' margins are evaluated taking into account they will have to also cover the cost of transmission.

- **Other factors:** the impact of variation of other factors, such as O&M, emission costs, taxes, etc. have also been considered. Even when their quantitative impact may be smaller, in some cases in which the business case of a given plant is border-line, they can influence the investment decisions.



		Impact of size	Impact of discount rate			Impact of capacity factor			Analyzed ranges
Capacity factor	35%	35%	35%	35%	35%	35%	20%	20-35%	20-35%
Size (MW)	50	10-100	10-100	10-100	10-100	10-100	10-100	10-100	10-100
Interest - DR	6.5%	6.5%	3%	10%	3-10%	3%	10%	3-10%	3-10%

	FIT	Wholesale market	Spot market
Min. Value	119	83	26
Max. Value		101	95

Figure 182. Example of simulation and sensitivity analysis – On-shore wind.

As depicted in Figure 182, the impact of the variations of any factor that may be relevant for a given business case have been evaluated. First in isolation, to understand its specific importance to a plant or project, and then combined with other factors, in order to evaluate the joint impact of several cost elements, and to provide a certain proxy for uncertainty of results.

An average of 40 simulations has been conducted for each region /technology pair, but only the most significant cases are presented in this report.

- Plants whose business cases result in costs much higher than the reference electricity market prices, or the maximum values of comparable plants have been eliminated. They would not be competitive. It would be necessary to fine tune either their technical characteristics or their operating conditions in order to obtain a viable business case

- Plants with excessively low costs are considered with care. Very advantageous results may be possible, but it is necessary to clearly understand the sources of excellence and competitiveness, to ensure they respond to achievable situations in the market, not to theoretical conditions.

Figure 183 describes the parameters depicted in each of the business case graphs shown in Section 5, why they are relevant for investors and policy makers, and how they have been computed.

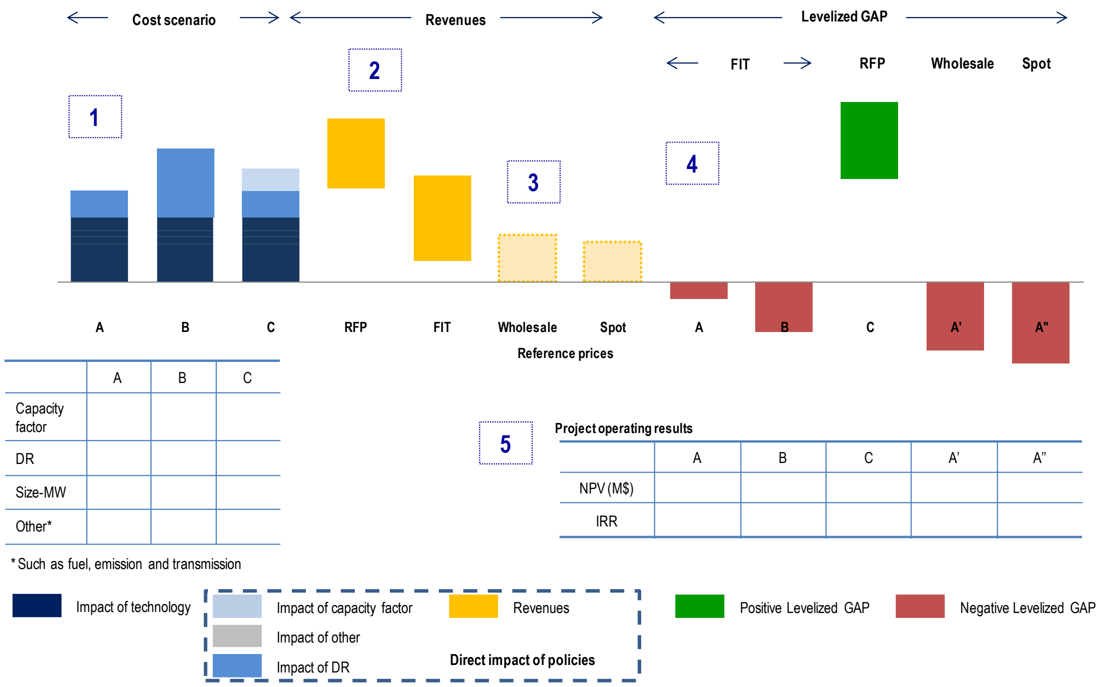


Figure 183. Example business case (US$/MWh)

1

Costs of generation are calculated by the model in an annual basis. These costs are levelized and depicted in graphical form (see Section 5) in order to allow their comparison with the results from other studies and policy documents. Blue bars represent the LCOE[394] of the plant in the input conditions.

2

Incentives are considered when the plant under consideration might be eligible to receive them. The incentives applicable in each region/technology pair that have been used in the computation of potential plant revenues are summarized in Figure 100. The model calculates the potential revenues that would be attained by a plant in the conditions defined for the simulation. Variations in the applicable compensations levels, potential revenue degressions, impact of inflation, and the impact of other parameters over incentives are also considered.

Variations of incentives over time – for instance the degression of a feed-in tariff value – are represented as ranges of prices in Figure 183. This enables to reader to see side by side the LCOE of a plant and the potential variation of unit revenues of the plant during its lifetime.

[394] Levelized Cost of Electricity. Please note that LCOE is represented in the graph, but it is not used as input to the business cases – non-levelized costs are. Or in other words: subtracting LCOE from unit revenue does not result in levelized m argins.

3 For plants that are not eligible to receive a revenue incentive, revenue consists of the compensation that the plant obtains by selling the electricity generated. This includes non-renewable technologies, or renewable plants operating in locations where incentives have been discontinued (on-shore wind in Spain after 2012).

Revenues are calculated using reference prices obtained from publicly available sources. Two prices are considered in each region – the spot market price, using the average value in 2011, and a reference wholesale price that is calculated by stripping retail prices of electricity from taxes, fees, and charges paid for transmission, leaving only the price of generation (see Figure 184). Variations of price levels over time may also be considered; although most of the business cases depicted in this report present the results of analyses assuming that the reference prices grow as the same rate as inflation. This mechanism allows comparing the performance of different plants under similar conditions. (See Section 2.6)

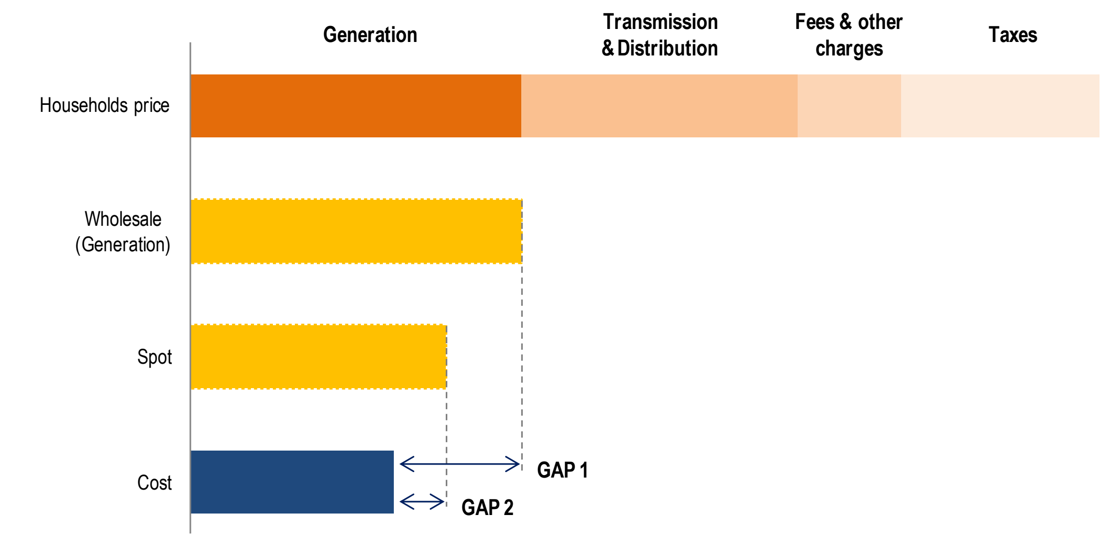


Figure 184. Example of wholesale price breakdown

4 With the simulated revenues and costs, and their potential variations over the life of the plant, a P&L is defined using common financing rules. To graphically represent income (revenue–cost), a variable denominated GAP has been defined. The GAP formula is represented below and results of subtracting the operating expenses (2), annual depreciation (3), debt payment and taxes (4) and equity compensation (5) from the plant revenues (1).

Using a levelized GAP instead of net income mitigates the impact of different financing structures (the proportion of debt and capital used by the plant), eliminates the impact of different SG&A[395] costs, and enables to graphically represent diverse business cases side by side. The reader may easily estimate ranges of income by subtracting the proportion of SG&A of a given project.

[395] SG&A – Selling, general and administrative costs have not been included to prevent adding a factor with large variations, and that depends on the type of company that is developing the plant, and selling the electricity produced.

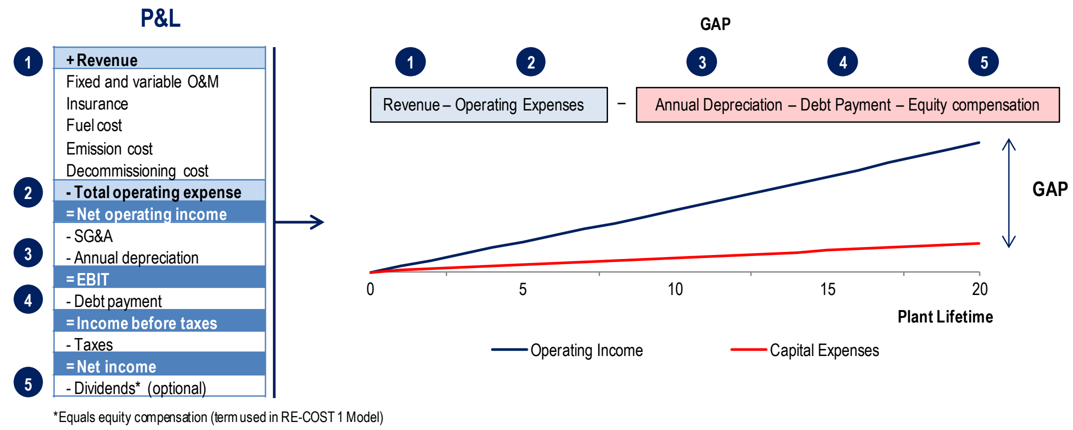


Figure 185. GAP calculation in the RE-COST

5 Financial ratios (NPV and IRR), obtained from the project P&L, are also depicted in the business cases graphs (see Figure 183).

6 Connection and transmission cost: Connection costs or grid infrastructure, that include the cost of connection to the grid during the construction of the plant, are included in the capital costs of the plants (blue bars representing "impact of technology" in Section 2.5). Transmission costs are not included in the graphs because it would increase the complexity of the graph. Its impact has been analyzed as discussed in section 6.10.

8.3 Main parameters and results

A special effort has been made to clearly indicate the inputs used in each simulation to enable the reader to reproduce the results displayed, and to compare them with the results of other studies. In most of the simulations, some variables have been maintained constant to minimize the variation of the results and to highlight the impact of other variables. Unless otherwise stated, the inputs used in most of the simulations are the following:

Simulation parameters	On-shore Wind	Off-shore Wind	Solar PV	Hydro	CCGT	Coal
Construction time, (years)	2	4	1	1	2	4
Economic/Book Life (years)	20	20	20	30	30	40
Loan/Debt Term (years)	20	20	20	30	30	40
Insurance (% Installed cost)	0.72%	0.71%	0.60%	0.60%	0.76%	0.69%
Heat Rate (US$/MMBTU)	n.a.	n.a	n.a.	n.a.	7,000	9,000
CO_2 Price (US$/t)	-	-	-	-	3 - 10	3 - 10

Figure 186. Technical factors – Values used in simulations

Emission Factors	Canada	France	Germany	Norway	Sweden	Spain	Japan
Natural Gas tCO_2/MWh)	0.468	0.392	0.322	0.322	0.214	0.339	0.438
Coal (tCO_2/MWh)	0.870	0.999	0.887			0.915	0.910

Figure 187. Emission factors per country and technology – Values used in simulations (tCO_2/MWh)

Reference Price Ranges	Alberta	Ontario	Quebec	France	Germany	Norway	Sweden	Spain	Japan
Spot market	76.2	31.5	27.9	63.6	66.4	63.9	65.4	64.9	152.4
Wholesale	95.1	57.1	27.9	74.8	92.2	44.3	91.8	98.8	103.8

Figure 188. Reference prices per country 2011 – Values used in simulations (US$/MWh)

A summary of outputs from simulations is provided in next table.

Country/Technology		Size[396] (MW)	Capacity Factor,%[397]	Capital Cost (USD/KW)[398]	Fixed O&M[399] (USD/KW)	Variable O&M[400] (USD/MWh)	Fuel Cost (USD/MMBtu)	Discount rate (%)	LCOE[401] (USD/MWh)
Canada - Alberta	Onshore Wind	50-90	30-35	1,400-2,200	19-23	12-15	n.a.	5-12	66-119
	Offshore Wind								
	Solar PV								
	Hydro								
	CCGT	300-800	30-75	1,400-1600	9-15	3.3-3.7	3.9-8.9	6.5-10	49-94
	Coal	250-600	20-35	1,600-4,000	10-35	0.5-6.0	1.3-3.1	7-11	49-127
Canada - Ontario	Onshore Wind	5-200	20-35	2,100-2,800	14-17	9.8-11	n.a.	3.5-8	84-138
	Offshore Wind								
	Solar PV	1-80	16-20	4,900-5,800	75-110	n.a.	n.a.	3.5-10	310-599
	Hydro	8-100	25-45	1,900-3,400	10-35	1.0-3.6	n.a.	5-8	44-110
	CCGT	300-800	25-75	1,400-1600	9-15	3.3-3.7	4.0-8.9	5-11	55-120
	Coal								
Canada - Quebec	Onshore Wind	100-130	20-35	1,700-1,900	12-18	7.5-12	n.a.	5-8	74-121
	Offshore Wind								
	Solar PV								
	Hydro	12-100	25-50	1,500-2,900	20-36	2.0-3.7	n.a.	5-8	67-92
	CCGT								
	Coal								
France[402]	Onshore Wind	10-80	20-35	1,800-2,200	13-23	7.7-13	n.a.	5-10	73-127
	Offshore Wind	400-750	35-45	4,400-4,500	31-41	15-20	n.a.	5.5-12	146-212
	Solar PV	1-50	10-25	2,000-4,600	40-42	n.a.	n.a.	6-10	118-301
	Hydro								
	CCGT	300-600	30-75	1,000-1,300	25-26	2.0-3.0	9.6-13	5-13	77-134
	Coal	250-600	30-60	1,500-3,700	15-35	1.0-2.8	2.2-6.6	7-13	60-130

Does not exist or irrelevant   Not included in the study

Parameters for country/technology pairs in scope (continue in the next page)

396 Size ranges do not include all existing generation plant sizes within the country, but ranges based on RE-COST database.

397 Capacity factor ranges reflect average capacity factor registered in 2011 in the country, optimal capacity factor for the technology and minimum values to analyze the effect of the capacity factor in LCOE.

398 Capital cost values collected during the interview process within energy sector and consolidated in RE-COST database.

399 Annual value, not levelized.

400 Annual value, not levelized.

401 LCOE have been obtained through the analysis of the effect of the different variables applicable, i.e. LCOE ranges are the result of a combination of different parameters (size, capacity factor, discount rate, etc.)

402 Minimum values for solar PV are aligned to new developer breakthrough plants (2012).

Country/Technology		Size (MW)	Capacity Factor,%	Capital Cost (USD/KW)	Fixed O&M (USD/KW)	Variable O&M (USD/MWh)	Fuel Cost (USD/MMBtu)	Discount rate (%)	LCOE (USD/MWh)
Germany	Onshore Wind	10-100	15-35	1,800-2,300	12-20	7.8-13	n.a.	5-10	67-131
	Offshore Wind	100-600	20-45	4,200-5,200	60-74	24-30	n.a.	6-12	155-374
	Solar PV	2-50	10-25	2,900-5,000	42-47	n.a.	n.a.	4-10	164-401
	Hydro	10-100	30-55	1,400-2,900	10-21	1.8-3.5	n.a.	5-10	35-75[403]/58-103[404]
	CCGT	300-900	30-75	650-1,000	25-26	2.0-3.0	9.6-15	5-13	86-124
	Coal	400-2,200	25-60	1,300-2,000	9-20	1.8-3.1	2.2-4.4	8.5-13	64-127
Norway	Onshore Wind	10-110	20-45	1,400-2,800	4.5-20	4.0-18	n.a.	5-10	46-130
	Offshore Wind	150-650	35-45	3,800-5,200	41-55	16-21	n.a.	6-13	134-253
	Solar PV								
	Hydro[405]	30-100	35-50	1,300-1900	4.7-9.0	0.8-2.4	n.a.	7-11/5-10	36-63/45-69
	CCGT								
	Coal								
Sweden	Onshore Wind	10-100	20-30	1,400-2,300	5.2-24	4.6-21	n.a.	5-10	57-118
	Offshore Wind	200-600	30-45	3,500-4,600	38-50	15-19	n.a.	6-13	121-235
	Solar PV								
	Hydro								
	CCGT								
	Coal								
Spain	Onshore Wind	15-100	20-35	1.600-1,700	10-17	7.9-13	n.a.	6.5-10	68-121
	Offshore Wind								
	Solar PV	2-12	15-25	4,400-6,000	31-45	n.a.	n.a.	9-12	200-484
	Hydro								
	CCGT	300-900	23-75	600-1,000	20-22	2.4-2.5	10-11	8-15	70-126
	Coal	400-600	30-60	1,500-2,500	13-21	1.0-1.8	2.2-4.3	8-15	65-142
Japan	Onshore Wind	10-100	20-30	2,300-3,800	21-32	18-27	n.a.	3-8	111-145
	Offshore Wind	100-600	35-45	5,100-6,600	40-53	15-20	n.a.	5-11	154-323
	Solar PV	1-10	15-20	4,000-6,000	80-115	n.a.	n.a.	3-8	256-387
	Hydro	15-100	15-22	3,300-8,700	34-90	5.8-15.1	n.a.	4-6	155-494
	CCGT	400-1,400	30-75	1,500-1,600	26-36	1.9-2.8	12.8-14.7	5-8	97-177
	Coal	400-800	25-60	2,800-3,400	35-42	2.8-3.5	3.5-4.9	5-8	87-176

Figure 189. Parameters for country/technology pairs in scope

403 Large-scale hydro plants in Germany (>10 MW).

404 Small-scale hydro plants in Germany (<10 MW).

405 Large-scale hydro plants (>50 MW)/ Small-scale hydro plants (<10 MW) in Norway.

9. ABBREVIATIONS

SYMBOL	DESCRIPTION
BC	Business Case
CAGR	Compound Annual Growth Rate, %
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CIF	Cost Insurance Fleet
CNE	Comisión Nacional de la Energía
CO_2	Carbon Dioxide
CPI	Consumer Price Index
DR	Discount Rate
DSO	Distribution System Operator
EEG	Erneuerbare-Energien-Gestz
EPC	Engineering, Procurement and Construction
EPCOS	Electric Power Co.
ETS	Emission Trading System
EU	European Union
FIT	Feed-in-tariff
GHG	Greenhouse Gas
Ibid	*Ibidem* (latin for “the same place”)
ICEX	Instituto de Comercio Exterior (Spain)
IDC	Interest During Construction
IPP	Independent Power Producer
IRR	Internal Rate of Return
LCOE	Levelized Cost of Energy
LDC	Local Distribution Company
METI	Ministry of Economy, Industry and Trade (JAPAN)
MMBTU	Million British Thermal Units
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
O&M	Operating and Maintenance
OEM	Original Equipment Manufacturer
OECD	Organization of Economic Cooperation and Development
OPA	Ontario Power Authority
OPG	Ontario Power Generation
OTC	Over The Counter
P&L	Profit and Loss
PPA	Power Purchase Agreement
PPS	Power Producer and Supplier
PV	Photovoltaic
RD	Real Decreto (Royal Decree)
R&D	Research and Development
RE	Renewable Energy
REC	Renewable Energy Credits
SEU	Specified Electric Utility
REE	Red Eléctrica de España

SYMBOL	DESCRIPTION
RENERGI - RENERGIX	Fremtidens rene energisystem
RET	Renewable Energy Technology
RFP	Request for Proposal
RPS	Renewable Portfolio Standards
RRC	Renewable Resource Credits
SG&A	Selling, General and Administrative (costs or expenditures)
T-REC	Tradable Renewable Energy Credits/Certificates
TRC	Tradable Renewable Certificates
TSO	Transmission System Operator
US$	U.S. Dollar
VC	Venture Capital

Figure 190. List of abbreviations used in the study

CONVERSION ENERGY/POWER UNITS		
1 KiloWatthour (kWh)	=	3.6 MegaJoules (MJ)
1 KiloWatthour (kWh)	=	3412 British Thermal Units (BTU)
1 Joule (J)	=	1 Watt Second
1 Joule (J)	=	1 Newton-Metre (N-m)
1 GigaJoule (GJ)	=	277.8 KiloWatthours (kWh)
1 British Thermal Unit (BTU)	=	1055 Joules (J)
1 GigaWatthour (GWh)	=	86 Tons of Oil Equivalent (toe)
1 TeraWatthour (TWh)	=	1 Billion KiloWatthours (KWh)
1 Watt (W)	=	1 Joule/Second (J/s)
1 Watt (W)	=	3.7 BTU per hour (BTU/h)

Figure 191. Conversion of energy/power units

10. PARTICIPANTS IN THE STUDY

An extensive number of experts have been interviewed in order to get the data and information necessary to complete the RE-COST study. Opinions and views of these managers were gathered in order to improve the understanding of the electricity sector, not only of the countries/regions included in the scope of the report, but also of other countries, such as the USA, UK, Denmark, etc. that may cast light on a number of aspects in the electricity generation sector.

Their input has been built into the analyses and thought processes of the study. The views, opinions and recommendations shown in this report are the exclusive responsibility of Prysma and cannot in any case be attributed to any person or institution unless it is specifically stated.

In the list are only shown the persons who have been interviewed and who have provided their input, and have agreed on being acknowledged.

NR.	COUNTRY	NAME	COMPANY
1	Canada	Amir Shalaby	**Ontario Power Authority**
2	Canada	Benoȋt Pepin	**RioTintoAlcan**
3	Canada	Darcy Johnson	**National Energy Board**
4	Canada	Jean-François Nolet	**CanWEA**
5	Canada	Jim Burpee	**CEA-Canadian Electricity Association**
6	Canada	José M. Sánchez-Seara	**NaturEner USA & NaturEner Canada**
7	Canada	Julie Grignon	**Ministrère des Ressources Naturelles**
8	Canada	Marc-Antoine Renaud	**Enercon Canada Inc.**
9	Canada	Wesley Johnston	**CanSIA**
10	Europe	Athanasia Arapogianni	**EWEA - The European Wind Energy Association**
11	Europe	Kevin Welch	**GDFSuez**
12	Europe	Matthias Herrmann	**E.ON Climate & Renewables GmbH**
13	Europe	Pierre Tardieu	**EWEA - The European Wind Energy Association**
14	Europe	William Hopkins	**RES Mediterranean**
15	France	Laurent Joudon	**EdF**
16	France	Thierry Lepercq	**SOLAIREDIRECT**
17	France	Timothée Ollivier	**EdF**
18	International	Colin Henderson	**IEA Clean Coal Centre**
19	International	Francisco Garcia Lorenzo	**First Solar**
20	International	Maureen Hand	**IEA Wind Task 26 Operating Agent, National Renewable Energy Laboratory**
21	International	Niels Nielsen	**IEA Hydropower Implementing Agreement**
22	Japan	Akiro Takahashi	**Electricity Market Division, Agency for Natural Resources and Energy**
23	Japan	Enrique M. Lima Lobato	**West Japan Engineering Consultants, Inc.**
24	Japan	Inoue Keisuke	**Tokyo Electric Power Company**
25	Japan	Iwata Akihiro	**NEDO**
26	Japan	John Popham	**Japan Wind development Co. Ltd.**
27	Japan	Masahiko Kaneko	**West Japan Engineering Consultants, Inc.**
28	Japan	Paul J. Scalise	**University of Tokyo**

NR.	COUNTRY	NAME	COMPANY
29	Japan	Professor Daniel Aldrich	**Purdue University and Tokyo University**
30	Japan	Ueda Yuzuru	**Tokyo Institute of Technology**
31	Japan	Yokokawa Shintaro	**The Federation of Electric Power Companies of Japan**
32	Nordic	Jan Schelling	**Statkraft**
33	Norway	Andreas Thon Aasheim	**Norwea (Norwegian Wind Energy Association)**
34	Norway	Arild Fallan	**Enova SF**
35	Norway	Bernhard Kvaal	**TrØnderEnergi Kraft AS, Norway**
36	Norway	Halvor Kristian Halvorsen	**E-CO Energi AS (Norwegian Hydro Power Company)**
37	Norway	Håvard Hamnaberg	**NVE - Norwegian Water Resources and Energy Directorate**
38	Norway	Kari Espegren	**IFE - Institute for Energy Technology**
39	Norway	Mette Kristine Kanestrøm	**Lyse Energi**
40	Norway	Rune Holmen	**Enova SF**
41	Norway	Stig Svalheim	**Vestavind Kraft**
42	Spain	Alberto Ceña	**AEE**
43	Spain	Ángeles Mora Sánchez	**AEE**
44	Spain	David Poza Cano	**IDAE**

Figure 192. Participants in the study

Some participants from the obtained interviews would prefer to remain anonymously and be acknowledged generically.

NR.	Name	Company
1	Confidential	**European Investment Bank**
2	Confidential	**French Energy Solutions Provider**
3	Confidential	**French Utility**
4	Confidential	**Spanish Utility**
5	Confidential	**Spanish Photovoltaic Company**
6	Confidential	**Japanese Photovoltaic Company**
7	Confidential	**Japanese Photovoltaic Company**
8	Confidential	**Developer in Japan**
9	Confidential	**Japanese Utility**
10	H.A.	**Japanese Wind Farm Developer**
11	Confidential	**Solar Industry**

Figure 193. Anonymous participants in the study

43 of the participants in the interviews for the study have decided to stay completely anonymous without any acknowledgement and reference regarding country, sector or occupation.