Sound Energy Policy for Europe

Pragmatic Pathways to a Low-Carbon Economy

ENERGY POLICY DIALOGUE—SPECIAL REPORT™

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THE EUROPEAN POLICY DIALOGUE PROCESS

IHS CERA's independent and fact-based analyses are central to the success and impact of the European Policy Dialogue research process. Summits and private meetings are an important element of this research process and provide feedback opportunities as the study continues.

IHS CERA acknowledges with thanks all participants in the Special Report. Members and guests are expected to make contributions in the form of content, opinions, and public data. However, research materials and analysis produced during the European Policy Dialogue reflect solely IHS CERA's independent position. IHS CERA alone is responsible for all data, analysis, and opinions expressed in the Special Report.

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*European Policy Dialogue Member.

SOUND ENERGY POLICY FOR EUROPE: PRAGMATIC PATHWAYS TO A LOW-CARBON ECONOMY— EXECUTIVE SUMMARY

INTRODUCTION: FROM "WHERE" TO "HOW"

Europe has set the goal to move toward a low-carbon economy by 2050. The specific target is to reduce emissions of carbon dioxide (CO_2) across the entire economy by 80–95 percent by 2050 from 1990 levels, with several staging posts along the way. The power sector would make disproportionately large emission cuts, moving to near-zero emissions by 2050.

With the goal in place, the strategy for getting there is under intensive development. Europe must now move from "where are we going?" to "how do we move in the right direction?" That is, policymakers and the industry need to move to a concrete analysis of what would be required to move toward this unprecedented and ambitious goal. Power is integral to everyday living and economic viability. Given the sheer size and complexity of the electric power system, it is imperative that the challenges and risks of moving to a low-carbon economy are carefully considered. The current reappraisal of the future of nuclear power among some member states following the Japanese nuclear incident at Fukushima adds to the significant challenge of moving to a low-carbon power system.

This report aims to contribute to the discussion of long-term energy policy within Europe and specifically to provide independent input as DG Energy develops its 2050 Energy Roadmap and its own long-term energy scenarios. The report makes three contributions within the power generation area.

- First, we have developed a cost-emissions trade-off matrix for policymakers and industry that makes transparent the trade-offs and implications of various power generation choices. The matrix shows the costs of fuel choices set against varying levels of CO_2 emissions. IHS CERA does not advocate a single optimum or best solution. All options involve trade-offs, advantages, and drawbacks. Moreover these trade-offs will vary for each member state. Our objective is to clarify some of the main trade-offs.

- Second, we have highlighted five policy enablers of decarbonization. For each enabler, we review the key issues and make practical recommendations that can help the industry move in the proposed policy direction. We consider that each of these five enablers could potentially play an important role in the quest toward a low-carbon power sector, but they are meant to be neither a comprehensive list at the exclusion of other important issues nor a sufficient condition of success.

- Third, we place particular emphasis on the role of natural gas. Natural gas is one of a number of technologies that will need to be deployed. A focus on natural gas is therefore selective. However, we highlight natural gas because we believe that much policy debate to date has failed to give a level of attention to the fuel proportionate to its potential role and the scale of its potential impact.

Our focus is on the power generation sector and in particular on supply-side options. We focus on power generation because this sector is the largest single emitter of CO_2 within the European Union, has the largest abatement potential, and perhaps has the lowest abatement costs. We focus on climate change and CO_2 emissions even though we highlight the trade-offs with security of supply and affordability. Our focus on supply-side options is not meant to diminish the importance of the demand side. Energy efficiency, a new model for energy services, and demand-side management among many other approaches are of great importance and covered in other IHS CERA research.

It will be important for the Commission to link up policy between climate action, energy, competition, transport/mobility, and other areas. An integrated energy and industry policy is needed.

The key conclusions and messages from the IHS CERA European Policy Dialogue are summarized below.

TRADE-OFFS

- **European energy policy needs to be constructed around three core priorities set out by the European Union: economic competitiveness, the transition to a low-carbon economy, and security of supply.** IHS CERA has previously described these three priorities as The Energy Trilemma.* Policymakers will need to make informed trade-offs among these goals. Each potential power generation source ranks differently according to the three metrics.

- **There is no technological silver bullet.** A portfolio of technology solutions from both the demand side and the supply side will be required to meet Europe's future power needs. All options include trade-offs, advantages, and risks. That does not mean, however, that they are all equally good. Given the considerable uncertainties that surround future technologies over such a long time horizon, policymaking needs to be predictable, coherent, and nonprescriptive and should minimize future regret costs.

INVESTMENTS, AFFORDABILITY, AND COSTS

- **Power market design needs to evolve across the European Union to set up a framework that encourages the required investment.** The move to a low-carbon power sector requires very significant capital investment. This includes investments in

  – CO_2-free energy technology that usually involve high upfront capital costs but thereafter either no or low fuel costs

  – conventional generation, for both primary power generation, possibly in conjunction with carbon capture, and backup for intermittent renewables

  – transmission, both within countries and across borders

*See the 2010 IHS CERA Special Report *Sound Energy Policy for Europe.*

About €70 billion per year on average will be needed for renewables and conventional plant additions over the next two decades, a significant increase over the past decade investment rates of around €45 billion per year. Over 20 years this is €1.4 trillion. These investments are unlikely to materialize with the existing market framework, which creates too many risks and uncertainties. The requirement for major investments will require the establishment of new frameworks for power markets—the so-called market design reform, one of our five key enablers.

- **There is a trade-off to be made between the level of emission reductions and the cost incurred.** Fuel substitution from high-carbon old technologies to lower-carbon and more efficient new fossil fuel technologies can reduce emissions in the power sector by as much as 58 percent at relatively low cost relative to 1990, based on today's demand levels. However to achieve greater cuts in emissions requires either the phasing down of fossil fuels to be replaced by zero-carbon technologies, such as renewables or nuclear, or the use of carbon capture applied to fossil fuel plants. Both options would further reduce emissions, but at extra cost.

- **Policy assumptions that fossil fuel prices—notably natural gas prices—will inevitably rise in real terms over time are not warranted.** Fuel prices are unpredictable, uncertain, and likely to be cyclical. However, an understanding of the resource and cost base of natural gas and coal suggests abundant potential supply of both commodities through 2050 and beyond. Recent technological breakthroughs in unconventional gas have significantly expanded the potential global and European recoverable resource base of natural gas.

  Scenarios assuming rising fuel costs and a rapid decline in renewable costs are also unlikely to materialize. Scenarios of commodity price inflation cannot be discounted, but it is the cost relative to alternatives that matters: there is likely to be some correlation between fossil fuel costs and the price of other commodities (such as steel and silicon) that make up the bulk of the costs of renewables.

  Moreover, fuel prices are dynamic and will respond to the competitive environment. Prices can be expected to adjust if other technologies expand significantly: the higher the level of penetration of zero-carbon forms of generation at a global level, the less pressure on global fossil fuel prices. This lowers the target point at which new technologies become cost competitive with the lowest-cost option of fossil-fired power.

- **The costs of newer technologies can be expected to fall over time.** The costs of deploying clean energy—notably renewables—will depend on the rate of future cost reductions. Cost reductions come about through a combination of research and development (R&D), market pressure and support mechanisms, and learning as global manufacture grows. IHS CERA's analysis of learning curves concludes that the high end of learning and global roll-out assumptions are needed to deliver a mix of renewables at cost parity with combined-cycle gas turbines (CCGTs) by 2050. It is therefore important that policy on R&D and market mechanisms supports the learning impact if cost reductions are to meet expectations. Moreover the current balance of policies is weighted toward deployment and could be more cost effective if rebalanced more toward R&D.

- **The imperative of reliable power supply will need to be reconciled with the expansion of intermittent—nonconstant—renewable power.** Substantial backup power capacity will be required to support higher levels of intermittent renewable generation even with transformational grid change and storage. These backup costs will be required not only in power capacity but also in the broader fuel supply chain, notably if gas is used as backup. The system cost, which is large and in addition to the stand-alone costs of renewable generating assets, needs to be recognized. The enormous operational complexity of incorporating large swathes of intermittent generation also needs to be recognized, and the resulting issues will need to be handled with the utmost attention.

- **The costs of decarbonization need to be recognized and balanced against the expected benefits.** The extension of renewables into the system will entail significant costs above lower-cost alternatives for many years. IHS CERA finds that subsidy costs—supporting the legacy investments made before renewables costs reach cost-competitive levels—could peak in 2020–30 at around €45–€60 billion per year. Subsidy supports are not expected to fall below today's levels before 2035 at the earliest and could continue at high levels through to 2050. If passed through on a pro-rata basis, this would add up to €100 to the average annual residential electricity bill and up to €2,000 to the typical annual business company. Although these costs are necessarily uncertain, it is clear that costs will be significant and likely in this range. These costs need to be weighed against the wider benefits to the macroeconomy and society. The big risk to power investment is that consumers will revolt and not pay for all of the decarbonization costs or that the costs will make the European Union uncompetitive.

- **The carbon market needs to be reformed to send a stronger and longer-term price signal to investors and consumers.** The European Union Emissions Trading System (EU ETS) carbon market should continue to take center stage in the pursuit of the decarbonization of the European economy, as it ensures cost-effective abatement through the deployment of clean technologies. Further targeted policies could undermine the primary announced intention of a market approach and increase the overall cost of decarbonization, and their interaction with the EU ETS should be carefully examined. However, a critical review of the current market arrangements should be conducted to

  – recognize the impact of targeted policies to support renewables and energy efficiency on the EU ETS carbon price and limit the induced structural carbon price uncertainty

  – strengthen the carbon price signal to provide investors with a longer-term incentive to invest in low-carbon technologies through either a tightening of the current cap and guarantees on banking beyond Phase 3 or the introduction of a carbon price floor

– broaden the range of sectors covered by the EU ETS when technically possible and/or supplement the EU ETS through the transformation of current energy taxes into their equivalent carbon content tax (e.g., through a review of the Energy Taxation Directive). Focusing on sectors that are not trade exposed would limit the competitiveness effects in the absence of similar carbon pricing in other parts of the world. The impact of border tax adjustments measures should be investigated further.

TIMING, OPTIONALITY, AND THE ROLE OF NATURAL GAS

- **The period to 2030 will need a two-pronged approach of continued use and investment in proven conventional plant as well as the buildup of zero-carbon technologies.** Although the option exists to deploy further renewables, to prove up commercial-scale carbon capture technologies, and to focus on demand-side measures, continued investment in conventional fossil fuel plant, which has a clear track record as a proven and cost-effective technology, is also indispensable. This build-out can be consistent with the planned trajectory to reduce emissions through to 2050. It is important that

  – long-term decarbonization goals do not deter the necessary investments in fossil fuel options in the early period

  – investments in the early period in fossil fuels do not lock in future emissions that frustrate further emission reductions

- **Policy needs to keep options open and not make early decisions that close off alternatives.** The period beyond 2030 presents wide technology choices and also major uncertainties on the maturity and cost of these technologies. The level of fossil fuel prices is also uncertain.

- **Natural gas–fired power offers policymakers a key policy tool: optionality.** In the period to 2030 natural gas can help meet power needs at low cost and within a framework of reduced overall emissions—especially through substitution for coal. This is widely recognized. However, less widely recognized is that the choice of natural gas in the first period leaves options open for the post-2030 period.

  – A build-out of natural gas–fired power before 2030 could transition into a backup role for renewables post-2030. The use of existing plants for backup would be much more economic than building dedicated backup for renewable capacity after 2030.

  – A build-out of natural gas–fired power could provide further emission reductions at a later stage through retrofitting of carbon capture as this technology comes to fruition.

  – In cases where carbon capture technologies prove inapplicable and where alternative zero-carbon solutions are not developed in a timely fashion, unabated CCGTs still offer the best fall-back position—certainly if concerns about natural gas prices and availability are dispelled—until lower-carbon options prove affordable and are deployed.

IHS CERA believes that natural gas is a low-regrets choice with significant option value. Policymakers should recognize the key role that natural gas can play in establishing a flexible and sustainable pathway in the power sector within a diversified low-carbon generating portfolio. This might extend to ensuring that enabling supply infrastructure is made available.

THE FIVE KEY POLICY ENABLERS

If Europe is to move toward its decarbonization goals, the following five enablers are important levers for the power generation sector.

- Reform of power market design
  - Power markets need a predictable long-term investment framework that reduces regulatory risks, rewards availability in addition to output, and provides incentives for renewables to contribute to system balancing.
- Carbon market reform
  - The EU ETS should be revised and/or supplemented by carbon taxation to strengthen the carbon price, broaden the sectors covered, and provide long-term visibility to investors and consumers.
- Clean technology support
  - Support should be rebalanced in favor of R&D as opposed to the current focus on deployment and should drive investment in least-cost technology at the best location.
  - A threshold for subsidy withdrawal should be defined to provide long-term visibility to investors and to contain support costs.
- A strong role for natural gas
  - Long-term decarbonization goals should not deter investment in gas-fired power and related investments over the next several decades that are required to bring early emission reductions at acceptable cost.
  - The natural gas industry needs a predictable long-term investment framework for infrastructure that reduces regulatory risk and provides incentives for accommodation of flexible and renewable sources of energy.

- Carbon capture technologies
    - Carbon capture is essential if fossil fuels are to play a role in the longer-term stages of decarbonization. Commercial-scale demonstration carbon capture power generation plants—for both coal and natural gas—need to be developed as soon as possible to give industry and policymakers a clearer view of the costs and practicality of carbon capture.
    - More R&D is required into the area of carbon usage as a possible alternative to underground storage.

CHAPTER I
INTRODUCTION: FROM "WHERE" TO "HOW"

Europe has set a goal to move toward a competitive low-carbon economy by 2050. The specific target is to reduce carbon dioxide (CO_2) emissions across the entire EU economy by 80–95 percent relative to 1990 levels by 2050, with several staging posts along the way. The power sector is expected to make a disproportionately large share of emission cuts, moving to near zero emissions by 2050.

With the goal in place, the strategy for getting there is under intensive development. In March 2011 the European Commission, under the auspices of the EC Directorate-General (DG) for Climate Action, issued "A Roadmap for moving to a competitive low carbon economy in 2050." The title highlights the crucial dual objective of reducing greenhouse gas emissions and doing so in an economically competitive manner. The Roadmap provides a high-level general framework. Also in March, the DG for Mobility and Transport issued a parallel, more specific initiative for the transport sector, the White Paper "Roadmap to a Single European Transport Area—Towards a Competitive and Resource Efficient Transport System." DG Energy is preparing a more specific energy Roadmap set of long-term energy scenarios which is scheduled for release toward the end of 2011.

IHS CERA created the European Policy Dialogue, a diverse forum for the exchange of views, to help provide input into the formulation of the Energy Roadmap 2050 and to enhance understanding of the related issues. The forum comprises representatives from industry, the Commission, and independent stakeholders such as nongovernment organizations and prominent think tanks.

IHS CERA's aim is to contribute to the Roadmap effort in three ways:

- First, we have developed a cost-emissions trade-off matrix for policymakers and industry that makes transparent in a clear format the trade-offs and implications of various power generation choices. The matrix shows the costs of fuel choices set against the level of CO_2 emissions. IHS CERA does not advocate a single optimum solution. All options involve trade-offs, advantages, and drawbacks. Moreover these trade-offs will vary for each member state and over time. Our objective is to clarify some of the main trade-offs.

- Second, we have highlighted five policy enablers of decarbonization. For each enabler, we review the key issues and make practical recommendations that can help the industry move in the proposed policy direction. We consider each of these five enablers to be potentially critical in the quest toward a low-carbon power sector, but they are not meant to be a comprehensive list at the exclusion of other important factors.

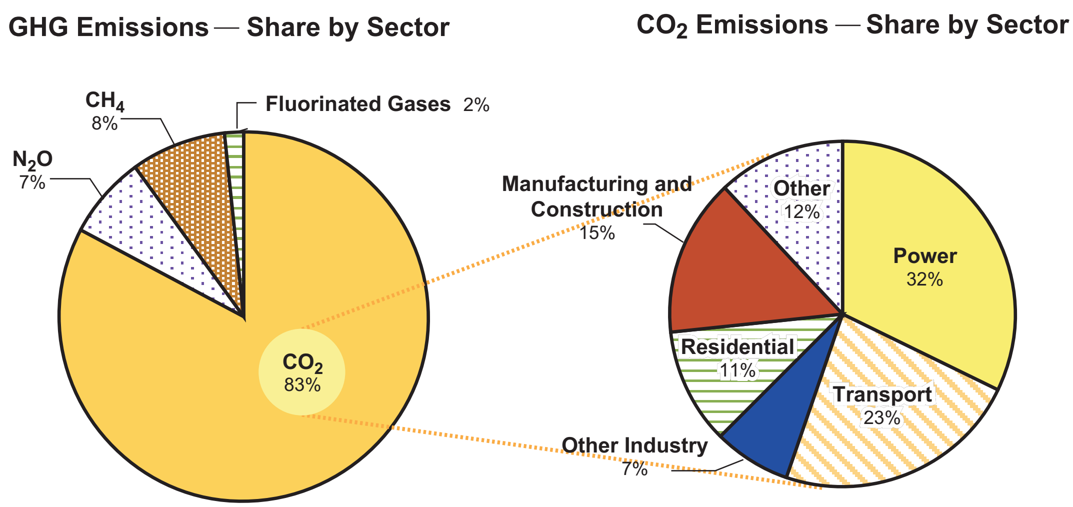
- Third, we place particular emphasis on the role of natural gas. Natural gas is one of a number of technologies that will need to be deployed. A focus on natural gas is therefore selective. However we highlight natural gas because we believe that much of the policy debate to date has failed to give natural gas a level of attention proportional to its potential role and the scale of its impact.

Our focus is on the power generation sector and in particular on supply-side options. We focus on power as the single largest source today of CO_2 emissions and, arguably, the area with the lowest-cost and widest array of carbon abatement options (see Figure I.1). Our focus on supply-side options is not meant to diminish the importance of the demand side. Energy efficiency, a new model for energy service, and demand-side management, among many other approaches, are of great importance and covered in other IHS CERA research.

IHS CERA held three summits in Brussels between October 2010 and May 2011 to discuss and debate the issues in this report. We would like to thank all those who attended and contributed (see Appendix for list of participants).

Figure I.1

EU Emissions—The Starting Point



Source: IHS CERA.
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CHAPTER II: THE TRADE-OFF MATRIX

European energy policy does not have a single objective: rather it needs to reconcile a set of objectives. The three primary objectives of European policy are security of supply, competitiveness, and sustainability. Two of these objectives are highlighted in the title of the European Commission's Roadmap 2050 document:

- move to a low-carbon future as part of the goal of sustainability
- maintain a competitive economy

The IHS CERA cost-emissions trade-off matrix examines fuel options through the lens of these two objectives. It provides a view of the scope, cost, and trade-offs of decarbonization in the European power sector, specifically,

- What percentage of CO_2 emissions can be cut by changing the existing power generation slate?
- What is the cost of the power generation slate options?

Our trade-off matrix provides extreme, or "pure," cases in order to highlight the boundaries of different alternatives. Unlike many other studies, it is not based on arbitrarily chosen combinations of power generation technologies.* Our simplified approach does not aim to represent likely outcomes or realistic scenarios for the evolution of the generation mix in Europe but rather to highlight the trade-offs in costs and emission reduction potential of different technology options.

In reality any outcome will be a mix of solutions—we do not imply that any single fuel or technology option should be adopted, nor that all should. The role of demand-side policies through energy efficiency and demand response will also play a decisive role and could significantly reduce the investments required on the supply side in the various cases we present. There is no "right" solution—only a clear menu of trade-offs. These trade-offs will vary for each member state and over time. However, there is a cost-emissions balance for each choice made.

We have analyzed the following six power generation slate options, which reduce emissions at different levels and at different costs, using the following assumptions.**

- **New coal.** All existing coal and oil capacity is replaced with best-in-class supercritical hard coal generation.
- **Natural gas.** All coal and oil capacity is replaced with best-in-class combined-cycle gas turbines (CCGTs) fueled with natural gas.

*The renewables case does involve a mix of renewables technologies, however.
**Hydropower is a low-cost zero-carbon option that has not been considered here, as the resource is limited on a Europe-wide basis, although it has significant potential to contribute to carbon emission reductions in certain countries.

- **Partial carbon capture and storage (CCS).** All coal and oil capacity is replaced by new units with CCS technology.
- **Full CCS.** All fossil fuel capacity, including natural gas, is replaced by new units with CCS. These carbon capture plants include both coal and natural gas plants.
- **Renewables.** All fossil fuel plants are replaced with a portfolio of renewable technologies, with gas-fired CCGTs used as backup for intermittency. The renewables portfolio evaluated is largely a combination of onshore and offshore wind.
- **Nuclear.** All base-load generation is replaced with nuclear power.

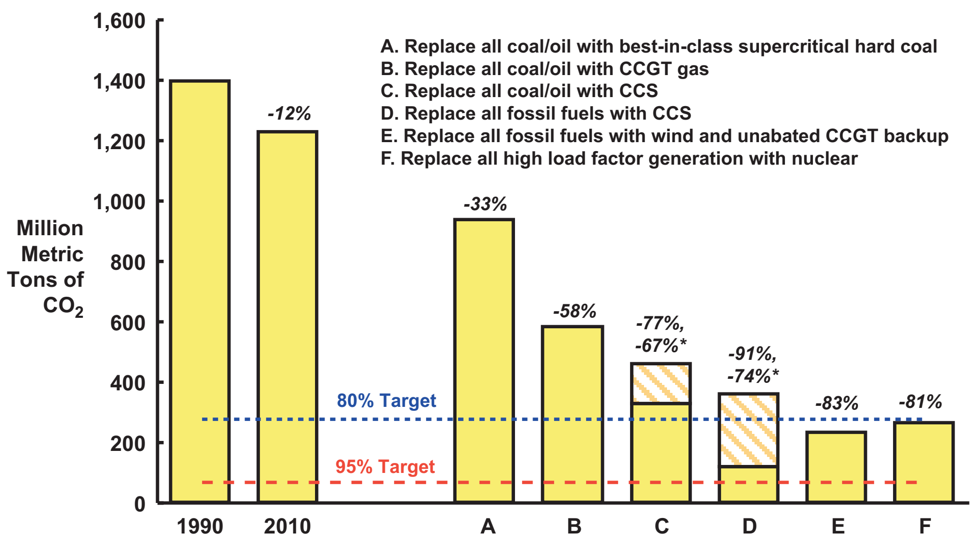
The analysis could be expanded to include a wider range of solutions. Most notably, various portfolios for renewable technologies could be examined. Also there are alternatives to natural gas as a backup to intermittent renewables: for example, pump storage also provides a highly flexible form of backup. However, these six distinct cases highlight the key choices and trade-offs.

EMISSION REDUCTIONS: HOW LOW CAN WE GO?

Figure II.1 shows the reductions in emissions relative to 1990. The following conclusions stand out:

Figure II.1

EU27 CO_2 Emission Reduction Potential: How Low Can We Go?



Source: IHS CERA.
*Sensitivity with 70 percent capture rate.
10614-2

- CO_2 emissions from power generation in the base year 1990 were 1,396 million metric tons.
- Emissions for the generating slate for 2010 are already down 12 percent relative to 1990. This is due to a combination of factors, including the restructuring of the former Soviet economies, extensive coal-to-gas switching in the United Kingdom, and the 2009 economic recession. However, the figures also include a 10 percent reduction resulting from the recent growth of nonhydro renewables across the European Union. Together these elements have more than offset the effects of growing power demand.
- Best-in-class coal-fired plants could reduce emissions by 33 percent.
- Use of natural gas could reduce emissions by 58 percent. This assumes that the fuel is based on 100 percent natural methane, whether conventional natural gas, coalbed methane, or shale. Use of biogas, green gas, or synthetically produced methane could lead to further reductions.
- CCS on coal and oil generation alone produces reductions of 67–77 percent. The reductions from CCS depend critically on the capture rates. We assume the target capture rates of 90 percent but also illustrate the sensitivity case of 70 percent capture.
- If CCS technology were also applied to gas-fired capacity, the reduction would be in the range of 74 to 91 percent, depending on capture rate.
- Use of renewables produces a reduction of 83 percent. This includes residual emissions from unabated gas-fired power as backup for intermittency; such backup is estimated to account for one fifth of total generation. It is therefore a critical issue whether other means can be deployed to support the reliability of renewables or at least minimize the need for backup. The two principal options are demand profile management and enhanced grid connections. Greater grid connectivity could allow complementary patterns in wind and solar conditions to enable renewables to back up renewables, including hydro, for system balancing. Gas-fired power as backup offers a much more localized solution, and a choice can be made between CCGT backup, which has higher efficiency (around 57 percent) at extra cost, and single-cycle plants, which have lower efficiency (around 40 percent) at a slightly lower cost.
- Increased use of nuclear for base-load generation would reduce emissions by 81 percent.

The reductions vary widely if considered for different member states. For example, Poland has the potential for large emission cuts by backing out unabated coal (with social implications to consider); whereas France, with a dominant nuclear mix, or Sweden, with large shares of nuclear and hydro, can make relatively few reductions in power sector emissions.

Note that we measure the trade-offs for future emissions reductions on a unit basis, i.e., CO_2 per kilowatt-hour of generation. No assumption is made about the rate of demand growth. There is a clear historical trajectory of climbing power demand at around 1.7 percent per year.* Unless active policies with respect to energy efficiency and demand-side management prove successful at reversing this historical trend, generation will also be needed for any incremental demand—making the task of reaching the absolute emissions goal that much harder.

The adoption of electric vehicles (EVs) would also add to power demand. However, in this case the additional emissions in the power sector should be set against the reduced emissions in the traditional transport area. The overall impact on emissions will depend on the marginal type of power generation used but would generally be negative: extra use of EVs would in most cases reduce overall emissions.

Improvements in the heat rates of thermal power plants could help reduce emission levels further. But the laws of thermodynamics mean that any incremental improvements will show diminishing returns; the scope for improvement is ultimately limited and quite small.**

HOW MUCH WILL IT COST? A THREE-STEP APPROACH

To illustrate the costs of each case in a transparent manner, we used a three-step approach.

- **Baseline.** Based on today's costs, what is the approximate cost of producing electricity using a levelized cost? We illustrate the cost for a range of capital cost estimates given the uncertainties around capital expenses (capex). This is particularly important for the high capex alternatives of nuclear, CCS, and most renewables.

- **Gas price sensitivity.** What is the impact of the gas price? This is obviously critical for the cost of the natural gas case since gas-fired power has relatively low capital costs but depends largely on the fuel cost. In the baseline, natural gas–fired power is seen as one of the lowest cost sources of high load factor generation on a levelized cost basis at today's gas prices and with the carbon price excluded. Hence, gas-fired power is considered as a reference—but this target point depends critically on the future level of gas and carbon prices.

- **Cost reductions (learning curves).** What is the likely range of future costs if we assume cost reductions over time? Cost reductions come about through a combination of research and development (R&D) and learning as global manufacture and deployment grow. Learning curves are typically associated with new emerging technologies, which may be high cost but have the potential for steep reductions. Either the market will drive the penetration of new technologies, if costs can be brought below the competitive benchmark, or external support is needed if the costs still need to be brought down to competitive levels. For new clean technologies the latter approach generally applies, but

*There is clear historical evidence that although energy efficiency has contributed to reducing power demand growth, it has been counterbalanced by new uses of electricity. Going forward, electrification of transport and heating through heat pumps could more than outweigh the dampening effect of energy efficiency on power demand growth.
**No attempt has been made to calculate the full life-cycle emissions for each case. That would include, among other things, fugitive upstream emissions for natural gas and coal and any emissions related to the manufacture of renewables equipment.

a transition mechanism to market competition at a suitable point in the evolution of each technology should be identified and enforced. Note also, however, that incumbent technologies may also continue to come down in cost, meaning that the competitive cost threshold is itself a moving target.

- The key uncertainties for policymakers are the future level of gas prices and the rate of cost reduction for clean technologies.

Baseline

Figure II.2 shows the baseline costs on a matrix set against the emission reductions achieved. The basic economic and operating assumptions used are shown in Table II.1. A zero price has been used for carbon so that the extra costs borne by society of a carbon price are transparent. In the section on carbon markets, we make the case for including a price for carbon—but this should be recognized as a cost to society that brings attributable benefits.

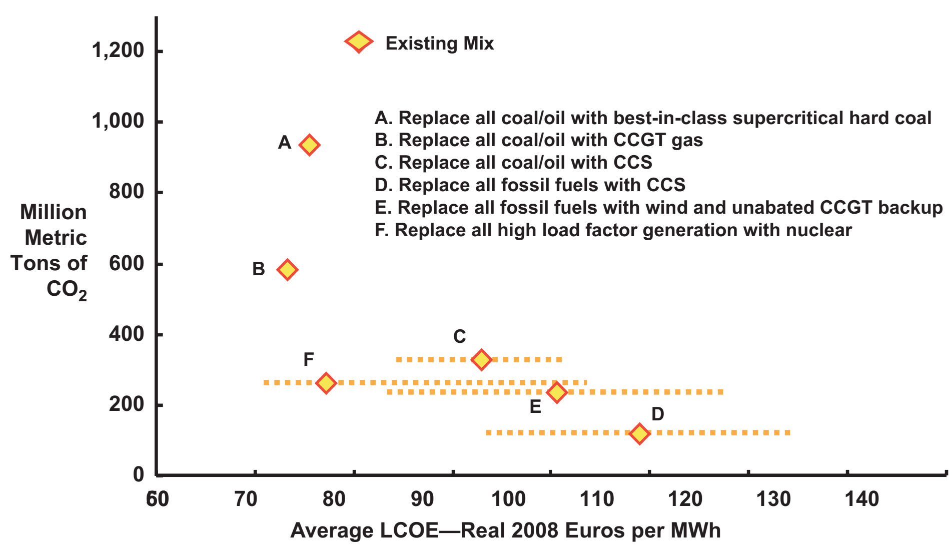
Natural Gas Price Sensitivities

The long-term future level of gas prices cannot be forecast with any level of certainty. Yet assumptions about future gas prices typically drive the results of studies. It is therefore helpful to ask what long-term gas price is required for competing technologies to reach cost parity with CCGTs if other fuel prices stay put.

- In the baseline we assume a gas price of €22 per megawatt-hour (MWh), which is consistent with recent levels.

Figure II.2

Cost-Emissions Trade-off Matrix: The Baseline



Source: IHS CERA.
Note: LCOE - levelized cost of electricity.
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Table II.1

Long-run Marginal Costs

	Nuclear III+	CCGT	CCGT CCS	Steam Coal	Steam Coal CCS	Gas Aero CT Peak	Onshore Wind	Offshore Wind	Solar PV
Capital cost including IDC (euros per kilowatt)	4,375	1,029	2,263	2,354	4,331	902	1,412	4,354	2,354
Capacity factor (percent)	90%	74%	74%	74%	74%	11%	25%	34%	11%
Variable O&M (euros per megawatt-hour)	1.0	2.0	4.0	3.0	5.0	1.5	15.0	32.0	0.0
Fixed O&M + other costs (euros per kilowatt per year)	100	20	40	40	60	15	0	0	30
Fuel price (euros per megawatt-hour)	2.5	22.2	22.2	12.9	12.9	22.2	0.0	0.0	0.0
Efficiency (percent, low heating value)	35%	57%	48%	45%	36%	42%	100%	100%	100%
Heat rate (MMBtu per kilowatt-hour)	10,035	6,703	7,973	8,015	10,035	9,017	3,412	3,412	3,412
Emissions allowance cost (euros per megawatt-hour)	0	0	0	0	0	0	0	0	0
Levelized cost of electricity (euros per megawatt-hour)	79	65	121	73	142	183	82	206	277

Source: IHS CERA.
Notes:
1 euro = $1.4
1 euro = £0.8
Gas price = 2.2 EURcent per kWh ($9.4 per MMBtu)
Brent = $102 per barrel
Coal CIF ARA price = $126 per ton
Lignite price = €1.5 per GJ
CO_2 price = €0 per ton
Post-tax WACC = 10.3 percent (nuclear, gas CCS, coal CCS, offshore wind)
Post-tax WACC = 8.4 percent (gas CCGT, steam coal, gas CT, onshore wind, Solar PV)
Solar PV = solar photovoltaic

The Levelized Cost Approach: Use and Limitations

The levelized cost valuation approach is widely used to compare the generation costs of different technologies and to inform policymaking, but it has significant limitations. In particular, it is difficult for the levelized cost methodology to incorporate risks and uncertainty effectively. The International Energy Agency (IEA) states for instance that "[the levelized cost] methodology for calculating generation costs does not take business risks in competitive markets adequately into account" and that "it needs to be complemented by approaches that account for risks in future costs and revenues."*

In practice, investors rely on more sophisticated valuation models to compare investment opportunities in different technologies. These investment valuation approaches include Monte Carlo simulation of a discounted cash flow model, Real Option and dynamic optimization models, and portfolio theory.

In particular, the traditional levelized cost valuation approach is not well suited to comparing technologies with different utilization rates and availability. For instance using the levelized cost approach to compare the costs of intermittent generation technologies such as solar PV and wind power generation does not capture the firming-up costs and backup costs that are required to ensure system stability.

IHS CERA has developed a proprietary methodology called the "Green Spread" to give a more accurate comparison of the generation costs of renewables and conventional dispatchable technologies, including the firming-up and backup costs associated with the required investment in backup peaking generation and transmission infrastructure.

For the purpose of this study, the use of the levelized costs does not undermine the results, as it provides a lower bound of the costs of intermittent renewables.

*Source: IEA/Nuclear Energy Agency (2005). Projected costs of generating electricity, 2005 update. OECD publication, Paris.

- Nuclear would need a gas price of between €23 and €53 per MWh to reach parity.
- Coal CCS would need a gas price of between €43 and €80 per MWh to reach parity, assuming no change in the coal price.
- Onshore wind would need a gas price of between €14 and €48 per MWh to reach parity.
- Offshore wind would need a gas price of between €49 and €138 per MWh to reach parity.
- Solar PV farms would need a gas price of between €67 and €193 per MWh to reach parity.
- Gas CCS must inevitably involve additional costs relative to unabated CCGT and can never reach cost parity by varying the gas price. Gas CCS would become increasingly more expensive as gas prices rise because of additional fuel costs to generate the same amount of electricity.

These price parity points demonstrate that either gas prices would need to rise to exceptionally high levels (on a sustained 20-year-plus basis) or the cost of competing technologies needs to be brought down significantly. For example, €50 per MWh is the energy equivalent to an oil price of $109 per barrel. The inclusion of carbon prices helps narrow the difference in costs with gas-fired power—but this is part of the implied cost to society.

In the section in Chapter III on the role of natural gas we argue that any assumptions that natural gas prices will inevitably rise throughout the period are unwarranted. Moreover the illustration of holding other costs stable is also unrealistic. It seems likely that a world of high gas prices might also be a world of high coal prices, high inflation, high cost of capital, and indeed high steel prices, which would affect the cost of wind power, albeit maybe to different degrees.

Cost Reductions and Learning Curves

The costs of technologies—both new and old—can be expected to fall over time. The costs of deploying clean energy—notably renewables—will depend on the rate of future cost reductions. These cost reductions are expected to come about as a result of different drivers, including the effect of R&D and of learning through efficiency and scale as global manufacture grows.

Learning curves are often used to predict the expected cost reduction of different technologies. They are generally defined as the percentage reduction in cost achieved for each doubling of global installed capacity.* This creates a dilemma for European policy. One policy choice is for Europe to take a leading, cutting-edge position in clean energy technology. However, if Europe rolls out new technologies in advance of others, Europe will at best necessarily be paying for the "early learning" through high costs. At worst, Europe could choose technologies that fail to yield sufficient learning benefits and are essentially defunct. This could leave Europe at a serious global competitive disadvantage. Conversely, if Europe were to wait and others were to move forward, the European economy could take advantage of global learning and produce power from clean technologies at a lower cost—but possibly at the expense of failing to develop leading frontier indigenous industries and green jobs.

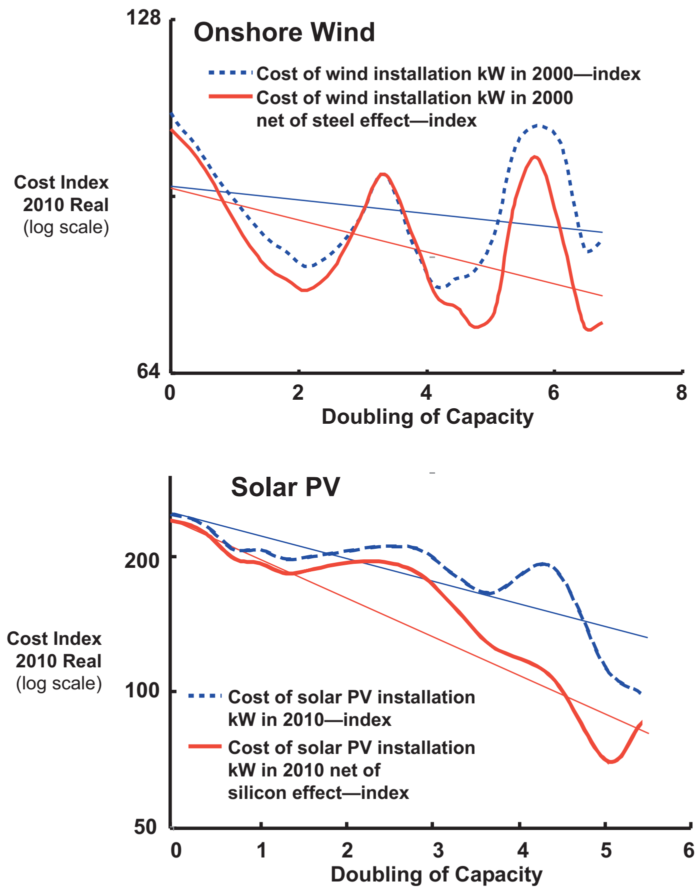
IHS CERA conducted an analysis of learning curves, with a particular focus on wind generation and solar PV (see Figure II.3). We also drew heavily from third-party literature. Our estimates for learning curves (percentage reduction in cost for a doubling of installed capacity) show a high level of uncertainty:

- 3–15 percent for onshore wind
- 6–18 percent for offshore wind
- 10–22 percent for solar PV

*Learning curves have also been defined in different ways in the literature, e.g., to capture the impact of R&D efforts, and to dissociate learning on a local basis from learning on a global basis, as some components of renewable technologies are global whereas others are specific to a local manufacturing industry.

Figure II.3

Historical Estimated Learning Rates



Technology	Learning Rate (percent cost decline for each doubling in installed capacity)
Nuclear	5% (2%–10%)
Fossil + CCS	10% (5%–15%)
Onshore Wind	8% (3%–15%)
Offshore Wind	10% (6%–18%)
Solar CSP	15% (10%–24%)
Solar PV	15% (10%–22%)
Geothermal	5% (2%–10%)
Biomass	5% (2%–10%)
Gas CCGT	4% (2%–7%)

Source: IHS CERA, IHS EER, and various third parties.
10614-8

Our analysis suggests that performance at the high end of these learning curves in combination with aggressive global roll-out assumptions will be needed to deliver a mix of renewables at cost parity with CCGT by 2050. It is therefore important that policy support for renewables penetration is appropriately tailored to provide sufficient support for R&D along with commercial adoption subsidies, and that the allocation can be flexible enough to pick the winners and drop the losers as the real levels of expected learning cost reductions become clearer.

Whereas learning curves are fairly reliable over a long period with sustained high growth, they can be seriously distorted by cycles. Commodity prices movements—for example the cost of steel for wind turbines—may obscure or negate any underlying cost reduction trend. Furthermore, a very sharp increase in the adoption of a new technology may lead to cost pressures through the supply chain as it scales up, as noted with the cost of silicon for solar PV cells. These effects ought to be temporary but can be significant, and good policy will seek to manage the pace of penetration within the capabilities of the industry.

Finally, a working competitive market among suppliers of equipment is a prerequisite if the cost improvements are to flow appropriately through to the consumer. Otherwise, the gains of learning could be absorbed through rents in the supply chain.

Feed-in tariffs are being widely used in Europe to support the penetration of renewables, with the expectation that the implicit support for learning mechanisms will drive the cost lower and levelized costs will be achieved. Although these have the effect of encouraging the investments which feed the learning, they also lock in premium costs for a period of up to 15–20 years and hence have a legacy effect. Based on our assessment of realistic learning rates and ranges of global growth of uptake, we assess that the burden of renewables support (including carbon pricing and grid infrastructure incremental costs) in Europe will grow by a factor of two to three between now and 2025 (peaking at a level representing an increase in electricity charges of around €100 per year per household and €2,000 per year per business entity) and is unlikely to be less than currently provided (around €18 billion per year in EU27) until 2035 at the earliest. In our analysis there is a substantial likelihood that residual feed-in costs (or the equivalent) will still need to recovered in 2050 and beyond.

CONCLUSIONS

The IHS CERA trade-off matrix demonstrates that the substitution of coal- and oil-fired power plants with new CCGT gas-fired plant is a relatively low-cost means of decreasing emissions. We estimate that the cost of producing electricity on a levelized cost basis (without accounting for carbon) from gas-fired plant is €65 per MWh and that today's emissions would be reduced by 58 percent relative to 1990 levels. The replacement of fossil fuel plant with nuclear plant for high-load-factor generation would reduce emissions by 81 percent at a similar cost level. The deployment of both CCS and renewable technologies would come at a greater cost.

The costs (as well as the benefits) of decarbonization therefore need to be recognized. Anticipated retirement of fossil fuel capacity replaced by the extension of renewables into the system will entail significant costs above lower-cost alternatives.

The analysis of locked-in subsidy costs for renewables highlights their sensitivity to two key variables: the magnitude of learning and cost reductions of renewables as well as the fossil fuel price evolution. IHS CERA finds that subsidy costs—supporting the legacy investments made before renewable costs reach cost competitive levels—will peak in 2020–30 at around €45–€60 billion per year and are not expected to fall below today's levels before 2035 at the earliest. In a medium-assumptions case, subsidy supports continue at high levels through to 2050. Although these costs are necessarily uncertain, it is clear that they will be significant and likely of this order of magnitude. A big risk to power investment is that consumers will revolt and not pay for all of the decarbonization costs or that the costs will make the EU uncompetitive.

CHAPTER III
FIVE POLICY ENABLERS

Various studies have suggested that it is technically possible for Europe to meet its goals to reduce carbon emissions by 80 percent from 1990 levels by 2050. However, to move toward this ambitious goal requires as a minimum starting point a conducive policy framework. The following five enablers could have an important role to play within the power generation sector:

- power market design
- carbon market reform
- clean technology support
- a strong role for natural gas
- carbon capture technologies

This chapter reviews each of the five critical policy enablers.

ENABLER NUMBER 1: POWER MARKET DESIGN

Why Is It an Enabler?

A number of studies demonstrate that the European Union's low-carbon targets are theoretically and technically achievable. Power market design will be absolutely critical if Europe is to move in that direction.

Large investments in the power sector will be required in Europe over the next two decades and through to 2050 to decarbonize the present generation mix. At the same time security of supply needs to be maintained through replacing and upgrading aging distribution and transmission grids.* According to IHS CERA's analysis, about €70–€80 billion per year on average will be needed over the next two decades for renewables and conventional plant additions, a significant increase over the past decade's investment rates. Over the next 20 years alone this implies a total of around €1.5 trillion. The legacy investment framework needs to evolve to adapt to this change in context. A number of EU member states have identified this priority and are actively engaged in market design reform exercises beyond those required by the existing Third Energy Package. The European Commission also needs to participate in this key policy area.

In some countries there are real concerns that private investors are not moving forward with investments in generation and transmission at the rate required. But this requires a supportive investment framework that clearly sets the directions and targets, allocates risks

*The UK government assessment (DECC consultation) states, "We have a huge investment challenge…. This means increased investment by existing market participants, and in addition, seeking investment from new sources of capital."

and responsibilities in a predictable and transparent way, and ensures a sufficient return on investment. The private sector can be expected to make the necessary investment on time and at a reasonable return if, and only if, the investment context is appropriately set up.

What Are the Issues?

The current power market framework in Europe needs to evolve to reduce risk and facilitate investment for merchant generation, facilitate integration of variable generation, and maintain security of supply.

Reduce Risk and Facilitate Investment for Merchant Generation

Large investments in conventional plants will be required to meet load growth and back up intermittent renewables. But although renewables are largely protected from market and regulatory risks, the returns for merchant generation in Europe appear low compared with the risks and uncertainties that investors face.

Investment regimes need to recognize which risks the private sector is best suited and less well suited to take on. Private investors are well placed to bear the construction risk (can the plant be built on time and cost?) and operation risk (can it be operated with high availability and efficiency?). Private investors handle less well policy and regulatory risks where they may require a high return to take on, such as out-of-market generation and mandated plant retirements.

Facilitate Integration of Intermittent Generation

Integrating renewables is a technical, economic, and policy challenge. On the policy side support for renewables remains very much a national or even regional issue. Coordination across countries remains a challenge, with the danger that projects are built in locations where the wind or solar resource is weak, leading to higher costs.

The other challenge is to coordinate renewables deployment with infrastructure investment, particularly network upgrades and new interconnection lines. In considering economic incentives and market design, the extent to which renewables projects are affected by power markets depends on the incentive scheme (i.e., feed-in tariffs [FITs], not at all; obligations, partially). Indeed, the level of incentivization is influenced by the power market structure, and that, in turn, influences the general level of public support. This raises the issue of incentivizing development of renewables to contribute to system balancing, just as other generation technologies are incentivized, and of renewables bearing some of the market risks.

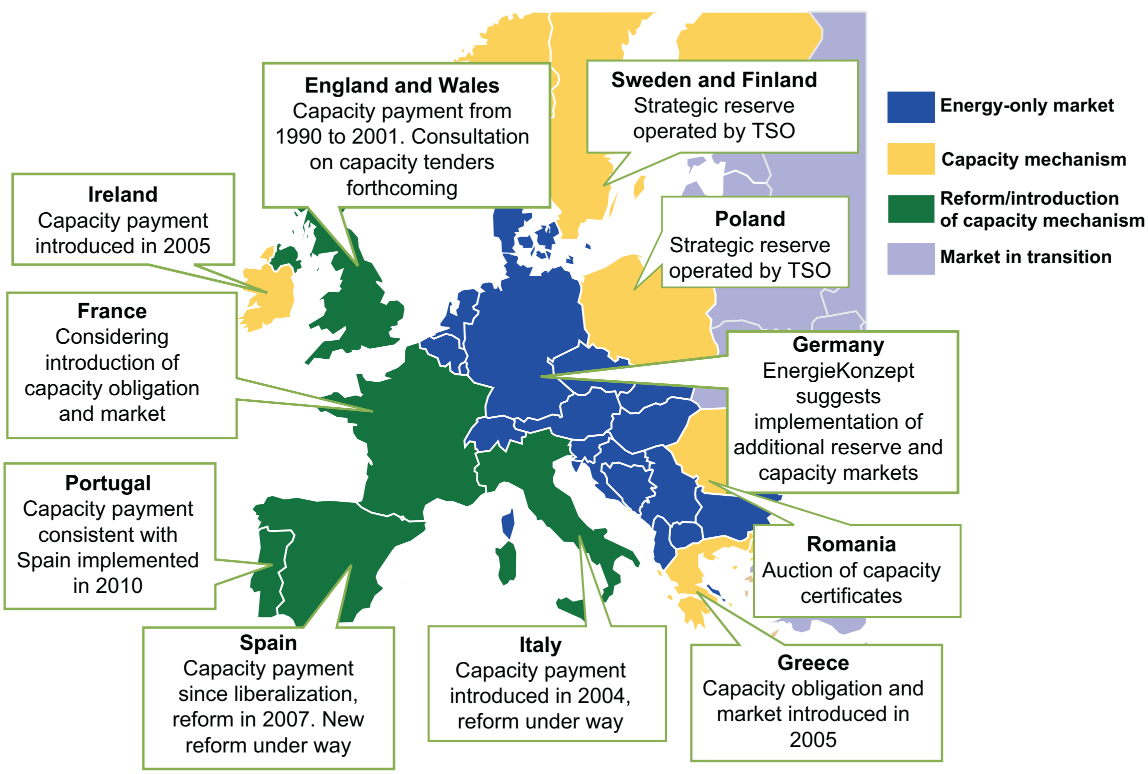
Maintain Security of Supply

The imperative for any government is to keep the lights on, as the costs of a power shortage to the economy are huge. This imperative to maintain constant power supply needs to be reconciled with the expansion of intermittent—that is, nonconstant—renewable power. The integration of large amounts of renewables will also reduce the running hours of conventional units. High power prices at times when fossil fuel plants are needed to back up intermittent renewables will be needed if these plants are to recoup their fixed costs, let alone make a profit. Prices may not be sufficient to prevent large-scale retirements of conventional power plants, given the new investments required to meet the forthcoming stringent emission standards introduced by the Large Combustion Plant Directive and the Industrial Emission Directive.

This raises the question as to whether the current remuneration of power plants, which is based on output (electricity actually generated), should evolve to introduce some remuneration of capacity and availability. Given the growing need to fill in the gaps of intermittent generation, the case for some form of capacity mechanism for generation becomes more compelling. The introduction of a capacity mechanism could provide a more stable flow of revenues for conventional plants and reward them for the service they provide to the system in maintaining security of supply (see Figure III.1 for an overview of capacity mechanisms in Europe).

Figure III.1

Capacity Mechanisms Throughout Europe



Source: IHS CERA.
Note: TSO = transmission system operator.
10614-6

Recommendations

Power markets need a predictable long-term investment framework that clearly sets the directions and targets, allocates risks and responsibilities in a predictable and transparent way, and ensures a sufficient return on investment. The framework should incentivize investment but leave the market to decide the best way of meeting the prescribed goals through responding to appropriate policy support and price signals.

More specifically, IHS CERA recommends that power market design be critically revisited as follows:

Reduce Risks for Investment in Merchant Generation

The current power market framework exposes merchant investors to regulatory and policy risks, which are hard to manage and restrict financing. Policymakers should revisit the current market arrangements with the aim to introduce a predictable long-term investment framework that ensures a fair return on investment by

- providing long-term directions for environmental legislation and carbon pricing
- supporting the construction of Europe-wide interconnection infrastructure
- streamlining permitting and licensing procedures

In addition, although construction and operation risks should remain with plant investors/operators, governments could mitigate and/or selectively take on some of the regulatory risks:

- Capacity payments/markets can stabilize plant revenues and facilitate financing.
- UK and French reforms suggest that some form of coordination may be necessary and compatible with the existing market framework. Key issues include the mandate and regulation of the central agency, which would decide what and when to build. The risk of system "gold plating" leading to extra costs for consumers would need to be carefully controlled.

Integrate Intermittent Renewables

Integrating large shares of intermittent renewables will require changes to market design to optimize use of existing infrastructure. The flexibility of the existing network and generation plants can be improved through market reforms to

- integrate day-ahead, intraday, and balancing markets
- optimize use of existing interconnection capacity, e.g., through market coupling
- provide better remuneration of reserve power and ancillary services

Renewables can and will need to be gradually incentivized to contribute to system balancing. Market reform can subject renewables to the same balancing obligations as other types of generation:

- balancing obligations: some renewables can be dispatched and/or can contract for backup power
- ancillary services: renewables can provide and/or self contract for, e.g., frequency response and reactive power

Ensure Security of Supply

Maintaining security of supply calls for greater coordination not only between network and generation investments but also among member states in implementing market reforms, as markets have become increasingly integrated on a regional basis.

Network and generation investments will need to be coordinated:

- Significant cross-border network expansion is a prerequisite to large-scale renewables deployment.
- Economic signals should be introduced to site plants where most needed on the network through cost-reflective transmission connection charges.
- The ten-year ENTSO European plan for development of network infrastructure should be extended to the longer term and take into account the deployment of intermittent generation.

The current focus on market design at the national level is at odds with the convergence of power markets and may lead to significant inefficiencies. Market reform needs to be coordinated at the European level:

- After a decade of (slow) convergence, European power markets designs risk diverging again without a coordinated approach to market reform.
- Regional market integration will be more challenging with the introduction of capacity payments/markets; hence a common approach to capacity markets is needed.

ENABLER NUMBER 2: CARBON MARKET REFORM

Why Is It an Enabler?

The European Union Emissions Trading System (EU ETS) was conceived as the key policy tool to drive reductions of carbon emissions in Europe and to meet the long-term objective of a low-carbon economy. Two fundamental principles underpin the ETS market: the idea that the polluter pays and the choice of a market framework as the most efficient way to abate emissions at the lowest cost.

The ETS carbon market was established in 2005 and has been growing rapidly. The market is maturing, and the reforms and adjustments for the second phase (2008–12) and the third phase (2013–20) have dealt with some of the early-stage problems. The market passed, with success, the test of its first demand shock with the 2008–09 recession, and there is evidence that it has driven some emission reductions since its implementation.

Whereas most renewables support policies remain the responsibility of member states, the ETS market is a truly European policy tool. As such, the ETS market has a key role to play by putting a price on carbon that will contribute to driving a cost-effective deployment of clean technologies throughout Europe.

What Are the Issues?

As the ETS market matures and grows, a number of issues have become apparent and call for reform, including the overlap of targeted renewables and energy efficiency policies with the ETS; the need to broaden the base of sectors covered by carbon pricing; the need to strengthen the ETS carbon price, which is believed to be too low and too short-term a signal to drive significant new investment in clean technologies; and the recent frauds, which highlight the lack of an appropriate oversight and regulation framework.

Overlap of Targeted Renewables and Energy Efficiency Policies with the ETS

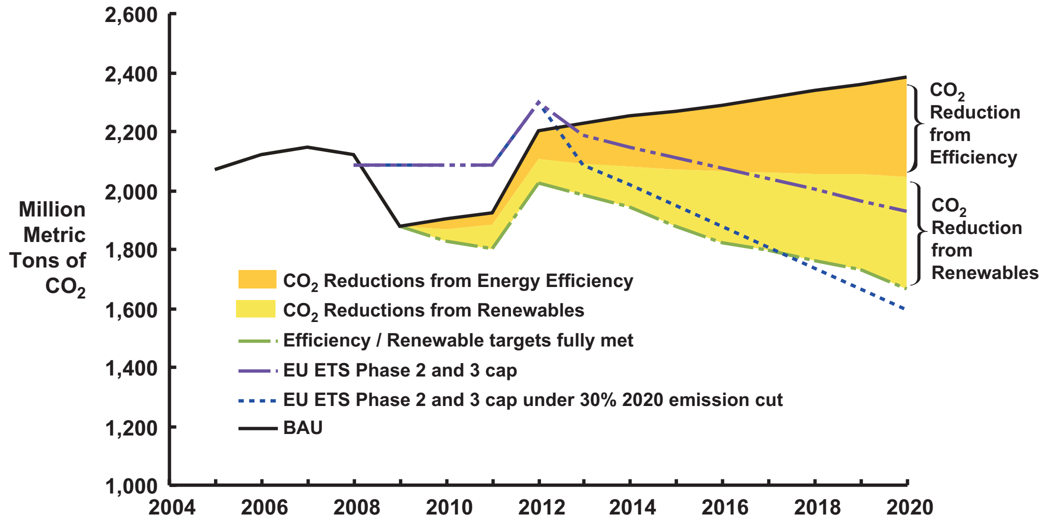
The carbon price needs to be sufficiently high if it is to encourage investment in low-carbon sources and discourage investment and operation of higher-carbon alternatives. However the parallel policy push to increase energy efficiency and support renewables drives the carbon price down, reducing its impact. The ETS carbon market cap is fixed and determined in advance for the different phases of the scheme. This cap determines the supply of allowances in the market. However, the demand for carbon allowances fluctuates depending on the economic activity but also depends critically on the efficiency of other policies to encourage energy efficiency and deployment of renewables.

By affecting the supply and demand balance in the ETS market, other national and European policies targeted at driving investment in renewables or improving energy efficiency have an indirect impact on the carbon price. These national renewables and efficiency measures thereby contribute to the structural uncertainty of the carbon price.

IHS CERA's research demonstrates that achieving the 20 percent energy efficiency target as well as the 20 percent renewables target would deliver equivalent CO_2 emission reductions greater than the abatement required under the current cap for Phases 2 and 3 (see Figure III.2). This undermines the case for any investment whose viability depends on the European Union Allowance (EUA) price.

Figure III.2

Impact of Targeted Policies on the EU ETS



Source: IHS CERA.
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Broadening the Base of Sectors Covered by Carbon Pricing

The ETS currently covers less than half of EU greenhouse gas (GHG) emissions. To create a level playing field and to drive abatement of carbon through the most cost-effective technology, the carbon price should in theory be applied across the largest set of sectors of the economy. In practice the scope of carbon pricing could be extended as a priority to sectors that are not trade exposed, such as the transport sector.

However, extending the ETS market to cover sectors such as transportation could be difficult from a technical point of view, such that a carbon tax complementary to the ETS carbon market might be better suited for these sectors. This would not necessarily require additional new taxes but could be done through the "greening" of existing energy taxes, such as the review of the European Energy Taxation Directive, to take into account the carbon content of various sources of energy.

Most importantly, introducing a carbon price for new sectors would raise issues about the competitiveness of Europe's economy in the absence of a similar carbon price in other regions of the world. In this perspective, the introduction of border adjustment mechanisms to correct for the impact of carbon pricing should be investigated further.

Strengthening the ETS Carbon Price

The postrecession price range in the ETS carbon market (€15–€20 per metric ton of carbon dioxide [tCO_2]) has an impact on the short-run dispatch of power plants and drives some carbon dioxide (CO_2) emissions abatement through coal-to-gas switching.

However, the current carbon price range is far below the levels that would equalize the long-run marginal costs of a new combined-cycle gas turbine plant with competing cleaner alternatives such as an onshore wind farm (€48 per tCO_2), a nuclear plant (€39 per tCO_2), or a coal plant equipped with carbon capture and storage (CCS) (€294 per tCO_2).

If the European carbon price is to drive the decarbonization of the power sector, carbon prices will need to send a stronger and long-term predictable price signal to investors and consumers. Various measures could be considered, including a tightening of the current emission cap, active price management through, e.g., emission set-asides, or the introduction of a carbon price floor, as in the United Kingdom.

The Need for an Appropriate Oversight and Regulation Framework

The repeated frauds in the ETS have highlighted the need for stronger oversight of the market and the difficulty of harmonizing carbon regulation among the member states. As the ETS carbon market has grown in volume and complexity, regulation has failed to keep pace. In the absence of appropriate rules, a patchwork of different regulations has left the EU ETS vulnerable to fraudsters.

Although positive changes are coming for Phase 3 trading with the introduction of registries, the suggested 2011 review of carbon market oversight is an opportunity to address the weaknesses in European carbon trade, either by bringing EU ETS regulation more in line with the oversight of European financial markets or by developing a tailor-made regulatory framework recognizing the specificities of the carbon market.

Recommendations

The ETS carbon market should continue to take center stage in the pursuit of the decarbonization of the European economy, as it ensures cost-effective abatement through the deployment of clean technologies according to their economic competitiveness. Further targeted policies could undermine the primary announced intention of market approach and increase the overall cost of decarbonization, and their interaction with the ETS should be carefully examined.

A critical review of the current market arrangements should be conducted to

- Recognize the impact of targeted policies to support renewables and energy efficiency on the ETS carbon price and limit the induced structural carbon price uncertainty.
- Broaden the range of sectors covered by the ETS when technically possible and/or supplement the ETS through the transformation of current energy taxes into their equivalent carbon content tax (e.g., through a review of the Energy Taxation Directive). Focusing on sectors that are not trade exposed would limit the competitiveness effects in the absence of similar carbon pricing in other parts of the world, and the impact of border tax adjustments measures should be investigated further.

- Strengthen the carbon price signal to provide investors with a longer-term incentive to invest in low-carbon technologies, through a tightening of the current cap (e.g., to a 30 percent cut) and guarantees on banking beyond Phase 3 and/or the introduction of a carbon price floor.

A more radical approach would be for the European Union to monitor the impact of various member state initiatives and intervene in the market to provide price support. When EUA prices are low, on account of an expansion of nuclear power, additional wind farms, or the success of energy-efficiency initiatives, it could buy or set aside allowances. Alternatively, it could sell allowances when prices exceed a targeted level. Most importantly policy recommendations for ETS and/or carbon taxation need to be made on a cross-European basis instead of the current piecemeal approach (e.g., the recent UK reform introducing a carbon price floor).

ENABLER NUMBER 3: CLEAN TECHNOLOGY SUPPORT

Why Is It an Enabler?

Investments in clean technologies will represent more than three quarters of the cumulative investments in generation in Europe in the next two decades. For Europe to follow an affordable pathway toward greater decarbonization, policies that support renewables and other clean technologies must recognize the maturity and anticipated cost reduction potential of the different technologies. Thereafter the support mechanisms can be targeted to provide cost-effective benefit while minimizing the risk of distorting market mechanisms.

What Are the Issues?

The current policy landscape in support of renewables and other technologies in Europe should be revisited with the aims of optimizing the balance between support for research and development (R&D) and support for deployment; assuring the affordability and cost effectiveness of current renewables support; and improving coordination of national/regional support policies.

Support for R&D versus Support for Deployment

Public support for R&D for renewables and other clean technologies remains low and uncoordinated in Europe, particularly compared with support for the accelerated commercial deployment of clean technologies. It is noteworthy that the United States has taken a different approach with a clear focus on support for R&D, whereas deployment is competitive within obligation targets.

In 2010 the European Commission published its European Strategic Energy Technology Plan, which aims to double public funding for research, development, and demonstration in Europe and coordinate national policies. This will include the definition of Technology Roadmaps over 2010–20. But there remains little visibility on how these road maps will be implemented and financed. One key issue is how to leverage private sector funding through public-private partnerships.

Questions about Affordability and Cost Effectiveness of Renewables Support

The growing system costs associated with intermittent renewables deployment have led policymakers in a number of countries to reevaluate support policies for solar photovoltaics (PV) and wind farms. We assess the current costs of support programs for renewable (FITs and green certificates) as adding around €18 billion per year to household and industrial billings or to government budgets where these are not passed through. Moreover these costs ignore the substantial additional grid costs passed through in regulated transmission charges. Rising end-user prices in difficult economic times have put pressure on policymakers to cut support for renewables, and this has often been done in drastic fashion—driving renewables implementation from feast to famine overnight in some countries. The pacing of growth of immature technologies is crucial in avoiding massive supply chain disruptions. This stop/start approach for European deployment subsidies in key countries has led to dramatic cost cycles for both wind and solar PV—an apparently counterintuitive response to the support objective of progressively reducing costs.

Even ignoring such supply squeeze effects, our analysis of the uncertainty about learning rates and global renewable deployment (see Chapter 2) implies that the burden (including assessed additional grid expansion costs) on end-user prices from ongoing support mechanisms needed to increase the share of renewable generation to around 60 percent by 2050 will grow strongly under all outcomes, peaking at 2.5–3.5 times current levels in the mid-2020s, and is unlikely to return to below today's levels until 2035 at the earliest.*

This is shown in Figure III.3, which illustrates that even as the premium cost of renewables comes down over time the total cost of subsidies continues to rise as a function of volume uptake.

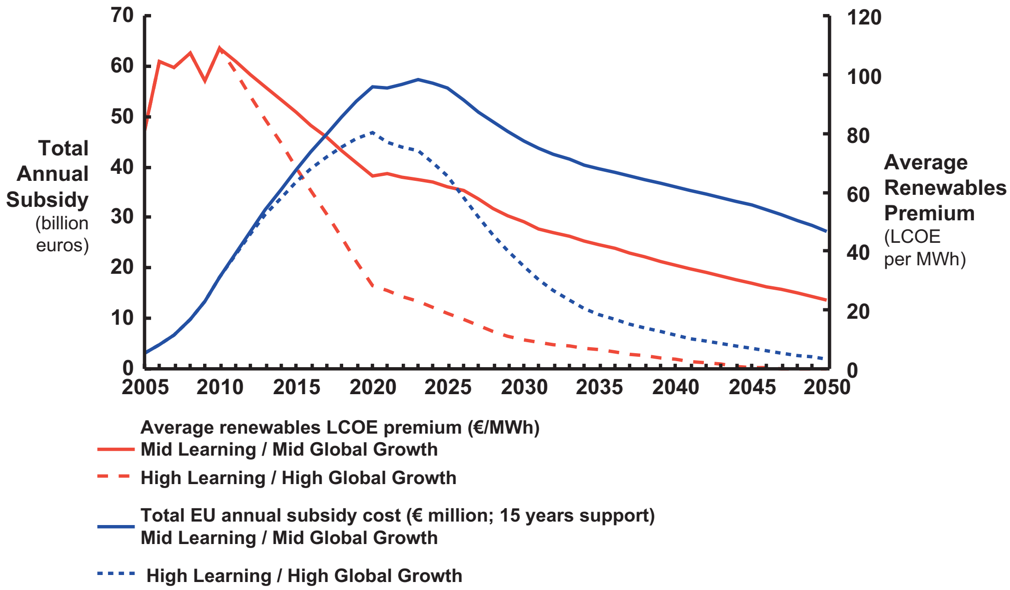
Governments will need to recognize that current support mechanisms will necessarily lock in a high level of additional cost long term. They will need to be prepared to maintain the mechanisms or potentially forgo the prize of ultimate cost parity for renewables. Depending on the outcome of learning and uptake, the burden may be expected to be eliminated prior to 2050 using our high end assumptions but may continue to be significant beyond 2050 with projections based on our midrange assumptions. Peak cost estimates of €45–€60 billion imply a cost premium equivalent to around 0.3–0.4 percent of gross domestic product, or up to €100 per household and €2,000 per average business company per year.

Nevertheless there is scope to manage the balance between the costs of support for clean technologies and the benefits associated with accelerated deployment. This can include taking into account the economic benefits from the creation of a domestic local industry that leads international development and production of the associated technologies, where this can be expected to prove sustainable. However a focused continuous review of the value

*This analysis assumes that most support mechanisms will continue to reward new-build renewables with locked-in market price premiums necessary to support the investment returns and external financing, based on the gap between market prices and the cost of the specific renewable generation cost at the time of build. FITs, which lock in such premiums for 10–20 years, are a typical example. This means that the system incurs necessary legacy costs, which still need to be paid from utility bills well beyond the time when renewable costs fall sufficiently to offset the need for such support. We apply 15 years as the average time frame for such legacy support for a simplified mix of on- and offshore wind, solar PV, and concentrating solar power (CSP), shown in Figure III-3.

Figure III.3

Uncertainty in European Renewables Costs Evolution— Representative Pathways



Source: IHS CERA.
Note: 60 percent renewable penetration in European generation in 2050.
10614-9

of deployment support for particular technologies and especially recognition of the point at which further innovation benefits are unlikely to be cost effective, or where penetration has reached a sufficient level for cost-competitive applications that the market can be expected to sustain sufficient further growth, is useful. These should constitute defined threshold conditions points for withdrawal of support for particular technologies and calls for a better understanding of the anticipated pathways and pacing for clean technologies deployment, costs reductions, and locked-in associated support costs.

Coordination of National/Regional Support Policies

Support for renewables and other clean technologies currently rests primarily with countries and regions that have complete freedom in how they choose to meet the 2020 renewables targets. While there are important local issues to take into account, this approach has resulted in a patchwork of policies with little coordination. Although it is important to understand when to withdraw support it should not be acceptable to attempt to pick winners up front at the expense of other emerging technologies. Another concern is that uncoordinated support policies might result in deployment of renewables in suboptimal locations with, for instance, poor wind or solar resource. The current mechanisms introducing flexibility for trade of renewables credits among European countries seem insufficient to ensure a coordinated and cost-effective optimized deployment of renewables across the whole territory.

Recommendations

Upstream support for R&D should be reinforced through

- a rebalancing of public support toward R&D as compared with support for commercial deployment of clean technologies
- redirecting new sources of European revenues such as the EU ETS auctioning and NER300 revenues as possible new sources of funding
- leveraging private sector funding through public-private partnerships, with a greater role for the European Investment Bank to mobilize the financial community

The rationale for support of clean technologies should be critically reassessed to create a level playing field:

- **Technology neutral.** Current support for specific renewables based on rationales such as carbon abatement or security of supply benefits should in principle be extended to all low-carbon technologies.
- **Technology differentiated.** Accelerating early deployment to drive costs down, as well as managing the pace of penetration to minimize supply chain disruptions justifies differentiated public support for emerging technologies—renewables and carbon capture.

The European clean technologies policy toolkit should be refined to contain costs, generate long-term visibility, and ensure affordability over support mechanisms:

- Define conditions that justify targeted additional support to accelerate learning and adoption of emerging technologies.
- Provide long-term visibility on targeted policies support by assessing the benefits of ongoing support and/or setting thresholds for withdrawal.

Clean technologies policy support lacks a coordinated approach among European countries in

- coordinating and harmonizing policies for deployment at regional, national, and European levels
- implementing further flexibility mechanisms to optimize the deployment of least-cost technology option at the best locations across Europe

ENABLER NUMBER 4: STRONG ROLE FOR NATURAL GAS

Why Is It an Enabler?

Natural gas today is a cost competitive form of power generation. The technology is proven and widespread. Emissions of CO_2 from a best-in-class natural gas–fired power plant are about half those of a best-in-class coal plant for the production of a unit of electricity. The smaller size of gas-fired power stations—relative to coal and conventional nuclear—can make them easier to site. The provision of the fuel through underground pipelines is also relatively benign environmentally.

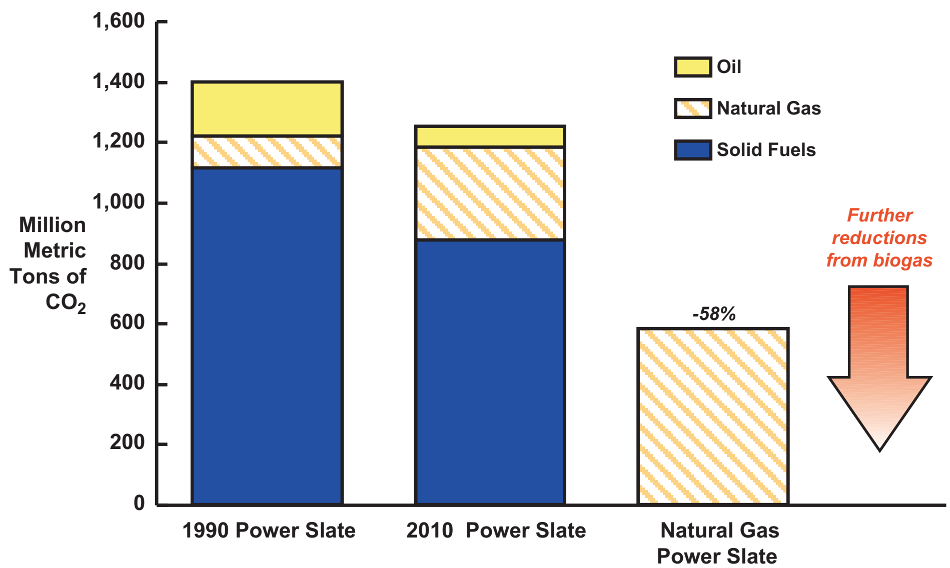
The IHS CERA trade-off matrix demonstrates that conversion of all coal- and oil-fired power generation to best-in-class CCGT would produce a 58 percent cut in emissions relative to 1990 (see Figure III.4). There is scope to cut emissions further if biogas or hydrogen were blended into the gas grid, although this would raise the cost of gas substantially based on today's costs. The use of cogeneration could also cut overall economywide emissions further.

Natural gas will likely remain cost competitive and hence a fuel of choice until or unless a combination of the following occurs:

- the gas price rises substantially
- the cost of zero-emission technologies comes down substantially

Figure III.4

How Far Can We Decarbonize with Natural Gas?



Source: IHS CERA.
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- CO_2 costs rise substantially or permitted emission limits effectively curtail unabated gas-fired power*
- reduced load factors imply substantially increased infrastructure costs, notably to cover the costs of pipelines and storage

The case for natural gas is compelling in the short term. The technology is proven and can scale up as rapidly as required (in contrast to renewable and clean coal technologies that may need time to scale up); the lead times for power plant construction are short relative to coal or nuclear plant; and there is for the time being a surplus of in-situ import capacity to Europe of large import pipelines and regasification terminals ready for use.

The environmental snag for natural gas is that any long-term plans aimed at phasing out fossil fuels could deter the investments in upstream gas production, power generation, and perhaps midstream infrastructure (pipelines, liquefied natural gas [LNG] facilities, storage) needed in the nearer term. But conversely, gas-related investments in the shorter term that involve assets with long lives risk locking in emissions into the long-term future unless gas-fired power stations can be retrofitted with carbon capture technologies.

What Are the Issues?

The key issues around the role of natural gas are availability, price uncertainty, security of supply, and the problem of locked-in emissions. The potential role of unconventional gas is also critical.

What Is the Global Availability of Natural Gas?

The world's natural gas endowment is considerable and at an early stage of exploitation, especially if we include shale gas resources. The global recoverable resource potential of natural gas is approximately 789 trillion cubic meters (Tcm), equivalent to about 250 years of production at today's level. Of this amount 404 Tcm is from conventional resources. The amount of unconventional gas is less certain. Global unconventional recoverable resources—based on separate estimates from the International Energy Agency and the Energy Information Administration—are around 385 Tcm. IHS research for North America, Europe, and China suggests that the global figure is likely higher. The potential to commercialize unconventional gas not only doubles traditional estimates of the world's natural gas exploitable endowment but also spreads the distribution among more continents and countries.

The total amount of natural gas consumed over the past century and a half is estimated at 93 Tcm, meaning that we have consumed perhaps a little over 10 percent of the resource to date.

*A high CO_2 price would render natural gas less attractive relative to non-CO_2-emitting sources but would improve its position further relative to coal.

Typical forecasts for natural gas consumption (that do not assume a phaseout of fossil fuels) are for market growth of between 1 and 2.5 percent per year. This would imply the cumulative consumption of between 155 and 215 Tcm over the 40-year period to 2050.*

Given the abundance of natural gas, IHS CERA therefore believes that policy should not be postulated on the idea of natural gas "running out"; rather the critical issues are an investment framework to ensure that resources are developed in a timely manner, the location of resources, and security and diversity of supply.

What Is the Level of Exposure to Price Risk in Gas-fired Power?

In our view the key challenge for natural gas is not the long-term level of price but volatility and cycles. Contract prices and spot-traded prices each involve different advantages and drawbacks.

Most natural gas in Europe is sold under oil-indexed contracts. The price is linked either to the international oil price or to refined oil products. This means that the gas price follows oil price cycles and movements. These prices will not necessarily reflect the supply-demand balance for natural gas and are subject to international geopolitical and speculative influences that may affect the oil market.

Spot natural gas prices tend to be volatile because both supply and demand are relatively price inelastic in the short term. On the supply side most of the costs are upfront capital costs and fixed: once these costs are made, there is little reason to regulate output according to price. On the demand side, for many consumers, especially the residential customer, natural gas is an essential commodity that cannot be comfortably be cut in response to a price signal. Storage can help to moderate this innate volatility, at a cost.

Volatility is problematic but is only one factor contributing to uncertainty and risks. Uncertainties and risks make planning difficult for business and subject consumers to unexpected price adjustments. However it is unclear that natural gas is necessarily worse than the alternatives. Intermittent renewables, for example, have a strong operational unpredictability. Nuclear energy and coal-based generation bear the risk of large upfront capital costs.

The long lead times to develop large-scale gas projects—large field developments, pipelines, LNG facilities—tend also to make natural gas cyclical.

In terms of price level, there is significant headroom for gas prices before they become uncompetitive with many alternatives. For CCGTs to produce power at the same levelized cost of electricity as the options below, the following indicative gas prices would need to be reached:

- €43–€80 per megawatt-hour (MWh) to reach parity with coal CCS
- €58–€150 per MWh for CSP

*Note that these resource figures do not include renewable sources of gas such as biogas (from landfill and waste) or synthetic gas (for example, that produced from hydrogen). Natural gas hydrates, whose scale is of a different order of magnitude, are also not considered since they are not expected to be economically exploitable for some decades.

- €14–€48 per MWh for onshore wind
- €49–€138 per MWh for offshore wind
- €67–€193 per MWh for solar PV

How Real Are Security of Supply Concerns?

The European Union imports 65 percent of its natural gas consumption. A large percentage comes from three countries: Russia, Norway, and Algeria. Meanwhile indigenous conventional gas production, which is produced predominantly in the United Kingdom and the Netherlands, is set to decline. Unconventional gas might help arrest or even reverse this decline but is unlikely to raise European production above today's level. Any policy that depends on extended use of natural gas will therefore imply increasing volumes of imports. The level of import dependence also varies widely by member state.

If security of supply is not to be a major concern, two conditions would help:

First, Europe needs sufficient infrastructure. At present Europe is estimated to have 38 days of average winter demand covered by existing storage. In fact Europe is in the process of expanding its gas storage. Europe has 86 billion cubic meters (Bcm) of current storage, 22 Bcm of storage under development, and another 74 Bcm planned or proposed. The level of cover varies widely by member state.

Infrastructure to Europe's border is also well developed; the issue is rather the diversity of supply sources and interconnections within Europe once the gas reaches the European border. A number of "gas islands" within Europe remain. Plans are already in place under the infrastructure package to improve interconnections and add reverse-flow capabilities. The problem may be access to capacity rather than physical congestion.

Second, there needs to be access to market-based and liquid gas supplies—both within Europe and an international, flexible LNG market. With respect to European hubs, the liberalization framework set by the Commission and introduced by member states has produced a number of trading hubs and reported benchmark market prices. Trading levels at these hubs are rising, although in most cases so far they lack sufficiently deep liquidity for effective long-term hedging of risks.*

Meanwhile, a global liquid traded market is emerging as a global LNG market grows. LNG need not be tied to a particular supply source, and therefore the LNG market can provide a form of resort in the case of supply disruption. LNG trade expanded more than 40 percent between 2007 and 2011 and is expected to continue to increase its market share of global gas. Most LNG is sold under long-term bilateral contracts, holding back the development of a short-term traded market, but it is becoming more flexible. The crisis in Japan—whereby LNG is being sourced to substitute for lost nuclear capacity—demonstrates the ability of

*See IHS CERA European Hub Tracker service.

LNG to provide a source of additional, emergency backup. Likewise the interruption of pipeline gas supplies to Europe from Libya has been countered with increased volumes of both flexible LNG and incremental pipeline supplies from other major suppliers.

Diversity of supply is critical. A high-level analysis by IHS CERA for the European Policy Dialogue demonstrates a trend over the past 20 years of increasing diversity of global gas supply in terms of both proved reserves and global gas production—when measured according to concentration indexes based on country-level aggregation. The diversity of gas imports into Europe has also been increasing as LNG volumes from a variety of countries increase: however, the diversity of European imports remains below that of both coal and oil.*

Finally, the existence of unconventional gas worldwide should provide some further reassurance about security of supply. Unconventional gas in North America has already meant that LNG volumes are no longer required in significant volumes in that market, increasing the availability in Europe and elsewhere. And, as argued below, Europe has its own unconventional resources that could provide a competitive response to external suppliers (while not dispensing with the need for imports).

Do Investments in Natural Gas Lock in Emissions?

Do investments made through the gas chain in the period up to, say, 2030 lock in emissions through to 2050? There is the potential for stranded assets, but the regret costs are relatively small. In fact, natural gas offers policymakers optionality on the future direction of policy.

- Power stations offer optionality with limited threat of locked-in emissions. A build-out of natural gas–fired power before 2030 could transition into a backup role for renewables post-2030. The use of existing, largely amortized plants for backup would be much more economic than building dedicated backup for renewable capacity after 2030. Alternatively, natural gas–fired power could provide further emission reductions at a later stage through retrofitting of carbon capture as this technology comes to fruition.

- In terms of the upstream, natural gas production has a natural decline rate as fields deplete. Once investment is stopped, the natural decline rate would potentially fit with a declining demand. Nevertheless some large-scale investments with long production profiles would need reassurance of continued market demand for up to 25 years after initial production.

- In terms of LNG, liquefaction and tankers need not be rendered redundant but could reorient potential trade to other markets where gas is still needed, notably Asia. Regasification facilities could become redundant assets—which would certainly be a concern for their owners and investors—but regasification is the lowest-cost part of the LNG chain and accounts for less than 10 percent of the costs of a full project, so compensation costs would be limited.

*A deeper treatment of the subject of the diversity of supplies, including a cross-comparison of natural gas versus alternatives such as coal, oil, uranium, and rare earths, would be beneficial and lies beyond the scope of this report.

- Pipelines have the longest asset lives and therefore have the greatest risk of becoming stranded assets. The regulated tariffs on transmission and distribution pipelines are based upon a long depreciation period (typically 30–50 years). In a decarbonized world some of these pipelines may find alternative uses, for example for the transportation of stored CO_2 or biogas (or even hydrogen). Indeed, gas companies have substantial know-how in the transport of gases. They could play an important role in contributing to solving the CO_2 transportation issue.

What Is the Scope of Unconventional Gas in Europe?

It is still early to assess unconventional gas potential in Europe. With only a handful of exploratory wells drilled to date, precise figures are not available; however, the existence of large formations is not in doubt. Geological information makes it clear that Europe has substantial resources. IHS estimates that resources within the European Union may be on a similar scale to those in the United States, with almost half the endowment located in Poland.

The costs are likely to be attractive. IHS estimates that the cost of development is in the range of €8–€9 per million British thermal units. These costs are significantly higher than the cost in North America. It is also higher than the supply cost of imported natural gas, whether by pipeline from Russia or via LNG. Critically, however, it is potentially cost competitive at oil-indexation levels if oil prices remain above $70 per barrel. Hence unconventional gas could provide an effective antidote to the risk of increasing international gas prices. Moreover the cost of producing power from unconventional gas at these price levels would be much lower than the cost of renewable power and coal CCS, as shown above.

The development of unconventional gas in Europe faces many obstacles, including environmental concerns, population density, complex geological formations (suggestive of higher costs than in the United States), the buildup of an onshore rig fleet, and the development of a regulatory framework. Consideration of these issues is beyond the scope of this report.

Unconventional Gas

One of the most important technical advances in energy supply so far this century concerns unconventional gas. *Unconventional gas* generally refers to tight gas, coalbed methane, and shale gas. The dual technologies of horizontal drilling and hydrofraccing have produced a boom in unconventional gas production in North America. Estimates of US gas resources have been increased by 18 Tcm since 2006. Production of shale gas—which was negligible in 2000—had reached approximately 180 Bcm (annualized) by mid-2011, more than the total gas production of any country in the world save Russia and the United States itself. It accounts for over 25 percent of total US gas production.

North America does not have a monopoly either on these resources, which are spread widely across the world, or on the related technology—much of the intellectual property resides with oil service companies that operate internationally. The international oil companies are also keen to take their capabilities worldwide.

However, the key policy take-away is that Europe faces a choice: it can either encourage the exploitation of this available, cost-competitive endowment in an environmentally safe and regulated manner or governments can decide to pass it over and opt for higher-cost but lower-carbon alternatives.*

Recommendations

- **Fuel of necessity.** Natural gas is indispensable as part of a portfolio of solutions in the near term and leaves options open for longer-term policy. Policy should therefore not discourage needed investment in all parts of the value chain over the next 10–20 years.
- **Gas availability.** Policy needs to recognize the global abundance of natural gas resources and should not be based on an assumption of a constrained resource base. Rather policy needs to encourage the necessary investments to diversify and secure supply.
- **Security of supply.** To encourage investment and security of supply, policymakers and regulators need to continue to support the emergence of liquid transparent markets and the interconnectivity between member states.
- **Include natural gas as part of an emissions offset ledger.** Industry and policymakers should investigate the possibility of including natural gas–fired power investments as part of a GHG emissions offsetting system. That is, investments in gas-fired power in emerging markets that can be demonstrated to reduce emissions from what they would otherwise have been could be credited to the European emissions ledger. This would encourage further cost-competitive emissions abatement from coal-to-gas switching internationally beyond what is available in Europe. This presents major challenges in practicalities and enforceability; however, given the large scope and cost savings available for low-cost emission reductions from building gas-fired plant relative to coal, it deserves closer examination.
- **Watching brief on unconventional gas.** Policymakers need to keep an active and close watch on developments in unconventional gas production both within Europe and internationally to see if there are early signposts as to its impact and potential.

ENABLER NUMBER 5: CARBON CAPTURE

Why Is It an Enabler?

There is significant potential for reducing CO_2 emissions from thermal power plants without resorting to carbon capture. As emphasized earlier in this report, the substitution of inefficient and old generating plant with best-in-class new plant fueled with natural gas offers a quick, cost-effective, and practical first step to lower emissions.

*For a detailed study of the prospects for unconventional gas in Europe, see the IHS CERA Multiclient Study *Breaking with Convention: Prospects for European Unconventional Gas.*

However, this approach can only go so far: thermal generation without carbon capture reaches a specific minimum level of emissions. To step further down the emissions ladder it will be necessary either to rely exclusively on nonfossil fuel options or to deploy carbon capture technologies on a grand scale alongside the nonfossil fuel options.

The question, then, is how to lock away permanently the captured carbon. Storage in geological formations—CCS—is the current favored solution but has many drawbacks. However, it may be possible to deploy carbon in useful ways, so-called carbon capture and use (CCU), rather than simply to treat it as a waste product. The particular attraction of CCU is that it may allow some of the burdensome costs of capture to be recouped. Given the overriding driver to keep as many options as possible on the table at this early stage of decarbonization, CCS and CCU must be retained as an option. There are no commercial-scale carbon capture power projects in operation in Europe and, as a result, a better understanding of the overall costs and technical trade-offs remains to be demonstrated.

A key driver of carbon capture is security of supply: capture technologies offer the prospect of relying on indigenous sources of coal, and potentially indigenous unconventional gas should that source also emerge. Use of carbon capture has traditionally been associated with coal-fired plant, because coal plants have the highest levels of carbon emissions, but the technology can also be applied to gas-fired and biomass plants if deemed desirable.

What Are the Issues?

The key issues for carbon capture are cost, social acceptability of storage, the availability of storage, and the prospects for alternative uses for carbon besides simple sequestration.

Cost

Given that no commercial-scale carbon capture power plant is under construction—let alone in operation—the costs are necessarily speculative. Nevertheless, the storage technology has been used in a few instances for many years in oil and gas production operations. At this stage we estimate that the inclusion of carbon capture adds 70 percent to the capital cost of a new-build coal-fired power station and increases the required fuel by 40 percent. It doubles the capital cost of a new-build gas-fired power station and increases the required fuel input by some 15 percent. Transportation and storage costs need to be added on top.

The comparative costs of coal versus natural gas carbon capture will depend in part on the coal-gas price differential. Because coal produces more carbon per unit of electricity than natural gas, it is often pointed out that the cost of carbon abatement (euros per ton of CO_2 captured) is favorable to coal. However, natural gas is likely to have two significant and enduring cost advantages:

- The capital expenses for gas carbon capture are estimated at €2,260 per kilowatt (kW), compared with €4,330 per kW for coal.

- The costs of storage will be lower. For each unit of power generated, natural gas produces approximately half as much CO_2 as a coal plant. Therefore the costs of CO_2 storage from a gas plant are also expected to be approximately half those from coal if it is done at a scaled-up level.

We therefore expect—contrary to commonly held views—that coal CCS may struggle to be cost competitive with gas CCS for new-build power generation. However retrofitting on old coal plant may more likely be a cost-attractive option.

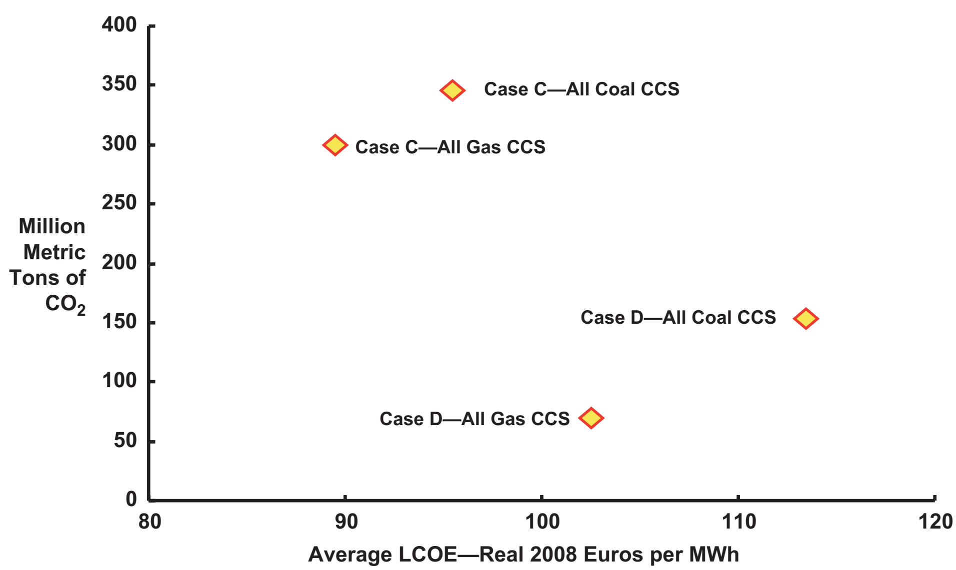
For the purposes of illustration, the IHS CERA emissions-cost trade-off matrix suggests that rebuilding the current fossil fuel generation fleet on the basis of coal CCS might add €54 billion to consumers' annual energy bills over the baseline. Rebuilding the fleet on natural gas would add €36 billion per year (see Figure III.5).

Social Acceptability

In some countries onshore carbon storage faces public opposition. The high population density of Northwestern Europe makes this region particularly challenging for carbon storage. Offshore options may prove more socially acceptable, but these require pipelines to move the CO_2 that also face social acceptability challenges. The public will need to evaluate the trade-offs of carbon storage relative to alternative energy solutions that present different drawbacks.

Figure III.5

Gas CCS versus Coal CCS



Source: IHS CERA.
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Availability of Storage

Lack of availability of storage could be a constraint on CCS rollout as a long-term mainstream solution. Depleted oil and gas fields in Europe offer an estimated theoretical capacity of around 20 billion metric tons—and maybe less in practice. This theoretical upper limit would be sufficient to store ten years' worth of CO_2 at today's levels. Aquifers potentially offer a much greater level of storage, but the geological understanding of using aquifers for this purpose is not yet sufficiently developed; more work needs to be done.

If there is a constraint on storage capacity, natural gas, which requires only half as much pore space for the same amount of power produced, has an advantage over coal. Changing the fuel mix from coal to gas could therefore extend the scope for CCS.

Emissions from any power station, however, will need to compete for storage space with emissions from industry. Since industry may have fewer storage options it may compete aggressively. This would increase the cost of storage and make CCS relatively less cost competitive relative to other generating options.

Carbon Use

The case for carbon capture would be enhanced if carbon could be put to practical use rather than being treated as a waste product. This would ease concerns on storage and potentially turn the costs of storage into a revenue stream to support project economics. The most obvious application is use of CO_2 for enhanced oil and gas recovery. CO_2 flooding is a well proven technique in the United States but has not yet been deployed in Europe. Our analysis suggests that this could handle between 4 and 11 percent of Europe's current emissions. Enhanced oil and gas recovery could play a useful role in kick-starting CCS. However, if enhanced oil and gas recovery is to be a valid alternative to simple storage, operators will need to ensure that the injected CO_2 is permanently stored and does not rise back to the surface.

IHS CERA undertook a high-level review of progress in frontier technology areas for carbon deployment. These include the production of building materials, CO_2 as a chemical feedstock, biochar, algae and third generation biofuels, and synergies between enhanced coalbed methane and CO_2. Although there are a number of exciting niche opportunities, the prospects for large-scale deployment of carbon look challenging today.

Recommendations

- **Commercial-scale power generation plants with carbon capture should be developed as soon as possible.** Commercial testing is needed to provide greater evidence from which private industry players and policymakers can make better informed decisions about the viability and role of carbon capture. The construction of "capture ready" plant (allowing the retrofitting of future capture technology) is sustainable only if commercial testing is planned and rolled out.

- **CCS and CCU should both be treated as fuel neutral.** That is, they should be considered an option for natural gas, biomass, biogas, and coal, without discrimination.

- **Extraction to injection.** Industry and national governments should step up efforts to switch the offshore oil and gas licensing regime to facilitate its transition from an extraction quarry to a future CO_2 storage park.

- **CCU should be part of the portfolio of decarbonization options.** More research into carbon use, or deployment, is required. The creation of valuable products from carbon would both improve the economics of carbon capture and ease possible constraints on storage. Even if deployment technologies fail to yield positive value, some of the routes under study could develop alternative ways to store carbon.

APPENDIX

THE EUROPEAN POLICY FORUM DIALOGUE: ACKNOWLEDGMENTS

This report is the product of a research process initiated and undertaken by IHS CERA experts for the IHS CERA European Policy Dialogue. All research materials and analysis reflect solely IHS CERA's independent position. IHS CERA alone is responsible for all data, analysis, and opinions expressed in this report.

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