



# POWER SWITCH: IMPACTS OF CLIMATE POLICY ON THE GLOBAL POWER SECTOR

## **KEY FINDINGS**

This report assesses the financial consequences of climate change policy for 14 leading global power companies. The key results are:

- Climate policy will have important consequences for power generation costs, fuel choices, wholesale power prices and the profitability of utilities. Even under conservative scenarios additional costs could exceed 10% of 2002 earnings, although with this come significant upside opportunities.
- Despite these significant risks, guidance from the power companies on the magnitude and form of potential risks has been scant. This suggests that companies are unprepared for these changes to their operating environment.
- All power companies are likely to gain from preparing for carbon constraints gains that come either as reduced potential losses and/or increased cost recovery if they switch from coal to less carbon-intensive forms of generation. This holds regardless of the allocation method used and at all realistic relative fossil fuel prices. Doing nothing is the worst option.
- At only €/tonne CO2e in Europe and US\$11/tonne in the U.S. switching from coal to gas-fired generation becomes the most economically attractive option for almost all firms.
- In terms of the pure cost burden, E.ON and Scottish Power are the most exposed European companies. At a carbon price of €20 (\$23)/tonne CO<sub>2</sub>e, each faces additional marginal generation costs equal to approximately 9% of 2002 earnings. Of 3 U.S. based companies, AEP has the greatest exposure under each price scenario.
- Even at carbon prices of €3-5 (\$3.5-5.5)/tonne CO<sub>2</sub>e, EU firms will be able to switch and generate substantial emissions abatements in excess of Kyoto-range targets, providing the coal-gas price differential is under *ca*. €4 (\$4.6) per MWh<sub>th</sub>. EU company abatements at €15 (\$17)/tonne CO<sub>2</sub>e total approximately 70 million tonnes, almost 10% of the entire EU power sector's CO<sub>2</sub> emissions in 2002.

Revised November 17<sup>th</sup> 2003

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This report is a revised version of the document released on November 12<sup>th</sup> 2003. Innovest has made a number of revisions to the original on the basis of feedback from the companies covered and a review of data. While these changes have led to modifications to some of the charts and small changes to the company results, they do not affect the overall key findings or conclusions of the report.

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## POWER SWITCH: IMPACTS OF CLIMATE POLICY ON THE GLOBAL POWER SECTOR

## KEY OVERALL FINDINGS

- Climate policies under development around the world will have important consequences for power generation costs, wholesale power prices, the economic attractiveness of fuel alternatives, and the financial viability of some power plants. These impacts will begin to be felt from 2004 onwards.
- There is reason to believe power companies will be caught off guard by these trends, as was the case during the recent power market deregulation process.
- The key criteria affecting power company exposure are:
  - i. The CO<sub>2</sub> emissions abatement requirements that may be faced
  - ii. The prevailing power market dynamics, including the relative price of coal and gas, the ability of companies to pass compliance costs to consumers, and green power incentives
  - iii. The nature of the existing generation portfolio, notably the proportion of generating assets in deregulated markets where carbon emissions constraints exist, and
  - v. The ability of companies to switch from high- to low-carbon intensity fuels.

Of these, the net cost burden on each firm appears to be driven largely by the method by which emissions rights are allocated and the extent to which costs can be passed on to consumers.

- Attaching a price/cost to the emission of CO<sub>2</sub> fundamentally transforms the cost hierarchy of the available fuel alternatives for generating electricity. At a price of around € (\$5.80)/tonne CO<sub>2</sub>e there are options available to the utilities that allow them to reduce their emissions at minimal additional cost. The price threshold may be higher in the U.S. [\$10/ tonne CO<sub>2</sub>e] and Japan owing to different fossil fuel prices. In any case, various schemes to support renewable generation across the world also provide CO<sub>2</sub> abatement options at low CO<sub>2</sub> prices.
- All power companies are likely to gain from preparing for carbon constraints gains that come either as reduced potential losses and/or increased cost recovery if they switch from coal to less carbon-intensive forms of generation. This holds regardless of the allocation method used and at all realistic relative fossil fuel prices. Early movers will clearly be able to lock in the benefits of switching sconer. The greatest risk arising from a switching scenario is exposure to natural gas price increases.
- Guidance from the power companies on the magnitude and form of potential risks and the corresponding management responses have been scant. There is reason to believe that companies are unprepared for climate policy changes, as happened during the recent push towards deregulation. The risks from being unprepared and inaction are potentially significant.

## **COMPANY IMPACTS & OUTLOOK**

14 major electric utilities are analysed in a region-specific model that estimates the effects of rising carbon prices on the generation portfolios under various regulatory scenarios. The analysis identifies key factors affecting corporate susceptibility to current and future climate policy developments, analyses the nature of potential financial risks and opportunities, and assesses how switching from high- to low-carbon intensive generation processes could affect company exposure.

- There are many options available to the utilities to deal with the impact of increasing prices on CO<sub>2</sub> emissions. Doing nothing is the worst option. By making astute changes to the fuel mix and investments to refurbish existing assets, profits may also increase.
- In terms of the pure cost burden, E.ON and Scottish Power are the most exposed European companies. At a carbon price of €20/tonne CO<sub>2</sub>e, each faces additional marginal generation costs equal to approximately 9% of 2002 earnings. Of the 3 U.S. based companies, AEP has the greatest exposure under each price scenario. Under a moderate carbon pricing scenario of €10 (\$11.5)/tonne CO<sub>2</sub>e, AEP's additional costs could total almost 8.5% of 2002 earnings.
- Even under competitive, unregulated market conditions, the net financial impact of carbon costs will be positive for some firms because they will be able to pass some of these costs on to consumers. For many, however, the added costs will not all be transferable. The biggest winner is E.ON because of the windfalls captured by its non-fossil fuel assets.
- The level of 'grandfathering' has considerable effect on net financial impacts however, it has little influence over a company's fuel switching decisions. Because grandfathering can lead to windfall profits for utilities even if they are highly carbon intensive, it is reasonable to assume that authorities will initially limit the use of grandfathering or arrange for CO<sub>2</sub> prices to be low.
- Even at carbon prices of €-5 (\$3.5-5.5)/tonne CO<sub>2</sub>e, EU firms will be able to switch and generate substantial emissions abatements in excess of Kyoto-range targets, providing the coal-gas price differential is under *ca*. €4 (\$4.6) per MWh<sub>th</sub>. EU company abatements at €15 (\$17)/tonne CO<sub>2</sub>e total approximately 70 million tonnes, almost 10% of the entire power sector's CO<sub>2</sub> emissions in 2002.
- In terms of costs 'saved' by switching, RWE and AEP have the greatest incentive to switch; rational fuel switching under a €20 (\$23)/tonne CO<sub>2</sub>e price regime could reduce costs by approximately €40-50 (\$46-58) million each. Southern, Duke, Endesa, Enel and E.ON could each see cost reductions of ca. €15-20 (\$17-23) million.
- The relative price of coal and gas affects the carbon price at which a fuel switch makes sense; a rise in gas prices of €2 (\$2.3) will deter companies from switching away from coal, and increase costs typically by up to 0.5x; if these added costs are passed through, windfall profits also rise as a result. RWE and, to a lesser degree, Scottish Power are the companies most sensitive to gas price increases.

# **1.** INTRODUCTION

The development of climate policy initiatives around the world and the resultant emergence of a price for greenhouse gas (GHG) emissions promise to fundamentally alter the economics of many industries. In view of its relatively high GHG intensity, the power sector is particularly exposed to this trend. Yet the precise nature of these 'emission risks', the factors that drive them, and the responses they should elicit from power company shareholders remain unclear at the present time.

In this study, we examine the potential financial exposure to global climate policy developments of 14 major electric utilities from around the world: AEP, Southern, Duke (from U.S.), TransAlta (Canada), TEPCO, Kansai (Japan), E.ON, RWE, Scottish Power, Scottish and Southern Electricity, Iberdrola, Endesa, Enel and MVV (from the EU). Our objective is to identify and analyse the key factors affecting corporate susceptibility to current and future climate policy. We examine the financial risks and opportunities that may arise and show how switching from high- to low-carbon intensive power generation processes could ameliorate companies' exposure.

# 2. CLIMATE POLICY ISSUES POSE A RISK TO UTILITIES

### THE POWER SECTOR IS UNDERGOING STRUCTURAL CHANGE

The power sector is currently experiencing a major change in its commercial arrangements. What was once a stable industry is being transformed by deregulation/liberalisation and the introduction of policy instruments designed to address concerns over climate change. These developments present a veritable 'perfect storm' for the power sector that over the next few years will fundamentally alter the competitive balance and influence the valuation of generation assets. At the company level, the net effects of these trends will differ according to:

- i. the regional distribution of company assets, notably the proportion of generating assets in markets where  $CO_2$  emissions constraints apply;
- ii. the prevailing power market dynamics to which the firm is subject, including the relative price of coal and gas, and the level of power market regulation;
- iii. the 'carbon intensity' of a firm's generation portfolio, the extent of natural gas-fired assets and involvement in renewable energy; and
- iv. the maturity of the corporate emissions management strategy.

## COMPANIES APPEAR TO BE UNPREPARED FOR THESE CHANGES

From an investor's perspective, the question of how prepared companies are for this shift in competitive conditions is a vexing one. Guidance from the power companies on the magnitude and form of potential risks and the corresponding management response have been scant. This view is corroborated by a recent PricewaterhouseCoopers study (Spring 2003), which found that only 58% of European electric utilities surveyed have climate policies fully or partly in place, despite the advent of the 2005 EU Emissions Trading Scheme. In the U.S. the figure is even lower: 39% of utilities surveyed have no policy, and 13% simply 'have the matter under consideration'. This should be a concern for investors in view of the impending nature of the issue and raises serious questions about the ability of utilities to manage climate-related risks appropriately.

### INVESTORS WILL NEED TO PAY SERIOUS ATTENTION TO COMPANY CLIMATE POLICY EXPOSURE

This would not be the first time companies in this sector risk being caught short by shifting competitive conditions. Many utilities - including RWE, Veba and Viag (now E.ON) - were caught unprepared for, and failed to realise that, deregulation/liberalisation exposed buyers and sellers of power to the price swings associated with other commodity processing businesses. Others embarked on investment programmes and/or entered into long term contracts that were completely unsuited for such volatile markets. As a result, the profitability and stock prices of many utility companies suffered.

With legislation to constrain emissions now a reality in many parts of the world and inevitable in others, the climate policy agenda threatens to have a similarly disrupting effect. Moreover, this comes at a time of sector-wide cost cutting, stock market underperformance and debt overload. Standard and Poor's reports 182 credit quality downgrades of utilities in 2002 compared with only 15 upgrades; 62% of electric utilities in the U.S. are just investment grade or below. Under such conditions, utility strategies for absorbing additional carbon-related costs and remaining attractive to investors are important.

#### CARBON CONSTRAINTS ARE A FACT OF LIFE

While the Kyoto Protocol has not yet entered into force, this should not obscure the fact that legislation encouraging the transition to low carbon intensity fuels, either through setting emissions limits or through introducing renewable portfolio standards (RPS) and other 'green incentives', is now a fact of life across the EU as well as in many parts of the U.S., Japan and Canada<sup>1</sup>. The EU is introducing a cap and trade system to limit GHG emission in 2005, on top of the direct support that many of its Member States provide for renewables-based generation. In the U.S. at least fifteen states have passed legislation or have policy to address  $CO_2$  emissions under consideration. Both Canada and Japan have ratified the Kyoto Protocol, are developing emissions trading frameworks and have incentives to encourage clean power generation technologies.

#### POWER MARKET DEREGULATION/LIBERALISATION WILL CREATE WINNERS AND LOSERS

Under the historic utility model of monopoly and vertical integration, the financial burden of compliance with CO<sub>2</sub> emissions requirements would not pose a problem; costs would simply be dealt with through ratebased negotiations between the utilities and the regulating authority. However, deregulation/liberalisation is fundamentally altering the allocation of risk between lenders, shareholders, fuel suppliers and customers, and leaving power firms more exposed to the vagaries of the market.

Firms considered to be high risk are those with carbon-intensive (that is, coal-based) generating assets in liberalised markets facing tough GHG restrictions, or those in regulated markets where a "gap" exists between federal and state environmental regulation and tariff policy. Low risk firms will be those in regulated markets which support additional transition costs or where returns are guaranteed, those not facing carbon emissions restrictions in the foreseeable future, those predominantly generating from clean sources, and those with only minor generating assets.

In assessing the impacts on power companies of the interaction of the deregulation/liberalisation process on the one hand, and the escalation of emissions constraints on the other, we therefore make two general observations:

i. For individual firms, compliance costs may not all be automatically transferable to customers. In competitive energy markets, "merchant generators", also called independent power producers, now need to pay much closer attention to how the price attributed to  $CO_2$  emissions might be redistributed throughout the market.

<sup>&</sup>lt;sup>1</sup> A summary map of global climate policy initiatives can be found at <u>www.panda.org/powerswitch/finance</u>.

ii. In fully deregulated/liberalised markets, wholesale power prices (WPPs) will rise to offset the costs of compliance. Spot wholesale prices are determined by the marginal cost of production (i.e. the cost of producing the last unit of electricity needed to meet demand). This means that wholesale prices will rise across the board by an amount broadly equal to the additional cost of emitting  $CO_2$  by these marginal generators. Some generators' costs will not be offset by the rise in WPPs, and net losses will result; for others, WPPs will rise beyond the compliance costs and profits will rise.

This is illustrated in Figure 1, which shows qualitatively how prices are set by marginal costs and how the differential costs of emissions allocations increase prices for each fuel.



Figure 1. Marginal Cost Curves for Various Fuel Types (a) With and (b) Without Emissions Permits

Source: Climate Change Capital

The architecture of regional power markets is therefore key in determining the net effect on any particular company. Where the marginal price is set by coal generation (e.g., UK and Germany), WPPs will rise by greater amounts than in regions where WPPs are set by gas generation (parts of the U.S., for example) because coal is more carbon intensive than gas.

The impacts of this are summarized in Table 1 below.



## Table 1. Net Financial Impact At Plant Level As Function Of Marginal Generation Type

Source: Climate Change Capital/Innovest

# **3.** CARBON RISK AT THE COMPANY LEVEL

## CARBON PRICES ALTER THE TECHNOLOGY ECONOMICS HIERARCHY

In terms of actually responding to these changing competitive conditions, reducing  $CO_2$  emissions and ameliorating financial risk, companies are limited in their choice of options. Unlike other pollutants, such as NOx and SOx,  $CO_2$  cannot yet be removed economically from smokestack exhaust by filtering or scrubbing (although we note that storage and sequestration may become viable in the future). This means that the only realistic way for power companies to comply, assuming they do not simply reduce output, is by continuing with their existing generation mix and purchasing emissions rights, or by switching technologies in favour of less carbon intensive fuels.

In deciding whether to continue with its existing asset mix (and, if the regulatory framework allows, buy permits), or to transition to a less carbon-intensive fuel mix, companies will be driven by the economics of each option. At low  $CO_2$  prices, purchasing allowances may be the cheapest and easiest way to comply.

As carbon prices rise, the economics of generating power from less carbon intensive primary fuel types improve. In this study, we have calculated the switching costs associated with making the following technology shifts:

- Switch from existing coal to existing gas plants
- Refire existing coal stations with gas
- Refurbish existing coal stations with new gas-fired technology
- Retire coal and build new CCGT plants

The relative price of the underlying coal and gas clearly has influence over the switching economics. This is illustrated in Figure 2, which shows the hierarchy of switching options available to companies and the carbon permit price at which the shift from coal to gas could occur at rising gas prices (assuming, in this case, a coal price of  $\leq 6.50$  ( $\leq 42$ )/tonne).



### Figure 2. Marginal Cost Curves for Various Fuel Types With and Without Emissions Permits

Source: Climate Change Capital

Switching costs for renewables can also be estimated, although these are currently applicable only on a regional basis because of differences in national policies towards renewables development. In the UK, for example, onshore wind is economic at the present time without any price put on carbon because of the additional value of Renewable Obligation Certificates, which currently trade at approximately 47/MWh. Onshore wind is also approaching cost-competitiveness in some areas of the U.S. because of the production tax credit.

The switching points (also referred to as breakeven points) depend on several factors, most notably the relative prices of coal and gas, the load at which the new plant is run, fiscal incentives employed to support renewables and the release factor (amount of CO<sub>2</sub> given off by each fuel upon combustion).

## CARBON PRICES WILL BE DRIVEN BY ABATEMENT OBJECTIVES

Predicting the actual price of  $CO_2$  emissions the market will bear is complicated by myriad uncertainties relating to supply and demand, the entering into force of the Kyoto Protocol, and other factors. Ultimately, the  $CO_2$  price will rise (or fall) as a function of the amount of  $CO_2$  to be abated and the number of buyers and sellers participating in the market. As abatement targets become more stringent, the price of  $CO_2$  will increase and with it the viability of low-carbon generation options. As an example, carbon abatement cost curves for the UK are depicted in Figure 3. Thus for the assumptions of gas and coal prices shown, some 22 million tonnes of  $CO_2$  can be abated if prices rise above about  $\mathfrak{C}$  (\$2.3)/tonne  $CO_2e$ .



#### Figure 3. CO<sub>2</sub> emissions abatement volumes and corresponding carbon prices for the UK market

Source: Climate Change Capital

#### IN AN EMISSIONS TRADING SYSTEM, HOW ALLOWANCES ARE ALLOCATED AFFECTS THE DISTRIBUTION OF BENEFITS BUT NOT THE INCENTIVE TO INVEST IN CLEANER GENERATION

Emissions trading is currently the climate policy tool of choice in many countries. As trading systems take shape, it is becoming clear that the way in which existing assets are treated within the system is a key determinant of the overall impacts on companies. Granting allowances in proportion to each plant's base year emissions ('grandfathering') is currently believed to be the most likely method to be adopted in the EU ETS. The greatest beneficiaries of this process, particularly if allowances are granted free of charge (as the EU scheme proposes), will be the coal-based generators, since these firms will be able to capture the greatest emissions reductions at lowest cost. Depending on the chosen base year, some firms may already be under-emitting, in which case they would capture the value of their excess rights in the marketplace.

Other allocation methods include allocation in proportion to plant base year output (output benchmarking), which would favour low carbon intensity plants, and allocation in proportion to base year outputs and inputs (fuel specific benchmarking), which would reward more efficient firms within each fuel use category.

In our model, the base case uses a grandfathering approach in which allowances are granted free of charge for 95% of a baseline target (as is the case in the 2005-7 pilot phase of the EU emissions trading system). To examine the implications of grandfathering on the bottom line impacts, we also present results for a nograndfathering scenario.

#### METHODOLOGY

To summarize, the extent to which firms find themselves in a winning or losing position depends on the following key variables:

• *"Energy Policy"*: the degree of power market deregulation/liberalisation in regions where the firm does business, and therefore the ability of the company to pass on policy compliance costs to customers.

The companies analysed in this report have generating assets concentrated in Western Europe, the U.S., Canada and Japan. Of these, the Japanese and U.S. markets still retain relatively high levels of regulation.

- "Climate Policy": the emissions regulations and green incentives that will alter the merit order of generation. As we have noted, this must include consideration of base year, the method of emissions permit allocation, and the market price of these permits.
- "Corporate Strategic Positioning": the carbon intensity of a firm's generation mix now and into the future, and its ability to deal skillfully with carbon management. We have examined the 'carbon intensity' of each company's generation mix (see Figure 4). In this chart, the blue column corresponds to total  $CO_2$  emissions reported by the company or another source. The gold column shows our estimates of  $CO_2$  emissions derived from the company thermal generation data used in the model to compute financial impacts reported subsequently. We note that Enel and Kansai estimates are much lower than reported levels due to unavailability of complete generation data for coal, oil and gas for these firms<sup>2</sup>. The emissions intensity is calculated by dividing our  $CO_2$  emissions estimates of total output of each firm in regions with possible carbon regulations (i.e., US, Europe, Japan, Canada).



# Figure 4. Company CO<sub>2</sub> emissions (reported and estimated from fuel mix) and emissions intensity per GWh in regions with carbon constraints covered in this report

 $<sup>^2</sup>$  The difference between the two estimates of total emissions is explained in the case of Kansai by the fact that much of Kansai's electricity is bought in from external producers. This generation is not covered in this report. Both Enel numbers are derived from Enel's own data on emissions and generation output: the company has not explained the inconsistency, so emissions data based on actual generation is used.

#### Source: Innovest/Company Reports

A company's preparedness for increasing carbon constraints was evaluated based on a number of considerations, including the level of market deregulation/liberalisation in that region of the world, the marginal generation fuel type, the level of carbon regulation, the carbon intensity of generation activities, and the strength of a company's abatement strategy.

Using this as a basis for understanding, for each company we employ a 6-step assessment procedure:

STEP1	*	Determine current split of company assets by fuel type (coal, oil, gas, hydro, nuclear and renewables), by exposure to carbon regulation and green power incentives, and by involvement in regulated/deregulated power markets.
STEP2	٨	Estimate $CO_2$ emissions from carbon regulated regions (actual & potential), and source of emissions by generating fuel
Step3	•	For different 'carbon prices' (the prices that could be attributed to $CO_2$ on account of tightening abatement regulations) model the shifts in generation between assets/fuel types (plus the concomitant reductions in company emissions) that the power companies <u>could</u> achieve were they to react according to the adjusted generation technology hierarchy at that carbon price. Emissions produced from the respective fossil fuel generation approaches are calculated according to:
		$CO_2$ emissions (coal) =[Generation (coal) x Release Factor (coal)] / Thermal Efficiency (coal).
		Release factors values (t CO2/MWh1h <sup>3</sup> ):0.341 coal;0.279 oil; 0.202 gas/CCGT; 0.202 gas/steam
		Thermal efficiencies: 36% coal; 38% coal-gas switch; 53% refurbished CCGT; 55% new CCGT
		These data allow for the construction of approximate marginal abatement supply curves for each firm. These curves delineate what companies could do (not necessarily what they will do) at a particular carbon price and correspond to our estimate of the volume of $CO_2$ each firm is able to cut as a result of this shift in generation mix.
Step4	>	Estimate the increases in marginal costs of generation due to increasing $\text{CO}_2$ prices for coal, oil and gas according to the equation
		Marginal Cost Increase = $CO_2$ price x (Fuel $CO_2$ Release Factor per MWh/Efficiency)
		Note: efficiency assumptions are: 36% coal, 39% oil, 53% gas/CCGT, 38% gas/steam
		We assume as our base case that 95% of emissions are allocated free of charge. Thus, under the base case scenario the proportion of a firm's coal, oil and gas generation subject to the additional marginal generation costs is 5%; under the 0% grandfathering scenarios, we assume that the additional costs apply to all of a company's fossil fuel generation. Each grandfathering scenario is modeled with natural gas prices at \$4, \$6 and \$8/mm BTU and a coal price of \$42/tonne <sup>4</sup> , based on the widely held industry view that the relative price of gas to coal will rise going forward.
		In this report we do not factor in the impacts of growth in electricity demand, or the implications that the fuel shift may itself have on fossil fuel pricing. In general terms, greater demand will increase emissions and the costs of meeting abatement targets and so raise the price of carbon dioxide allowances. Likewise, a widespread fuel switching outcome could drive up gas prices and so discourage further fuel switching from happening.

<sup>&</sup>lt;sup>3</sup> MWh<sub>th</sub> = Megawatt hour thermal

<sup>&</sup>lt;sup>4</sup> These prices were selected based on average price trends during 2002 and 2003, and gas/coal market forecasts as reported by the US Department of Energy, the Coal Association of Canada, Coal Week International, Platts Energy and London and New York commodities exchanges. Gas prices ranged between \$4 and \$6/mm BTU during 2003, whereas average coal prices in Japan, Canada, US and Europe have ranged between \$25-\$45/tonne depending on coal type and geographic region.

- **STEP6** > Express total costs and total net impacts as % of 2002 earnings as proxy for overall impact on shareholder value.

Because of the considerable regional differences in carbon regulation, energy market regulation, relative prices for fossil fuels, and renewable energy incentives, the company analysis has been split between Europe, U.S., and Rest of World.

### EUROPE

At present, the CO<sub>2</sub> emissions abatements that companies will face in Europe, the timelines over which these abatement targets will apply, and the carbon prices that will be generated are all uncertain. In view of this uncertainty, we have modeled the emissions abatements that each firm could achieve, and the net financial impacts assuming, at different carbon price points ( $\pounds - \pounds 30$ ) under 5%, 10%, 20% and 30% emissions reduction scenarios to 2012 (i.e., CO<sub>2</sub> cut by 5% - 30% below 2002 levels)<sup>5</sup>.

Figure 5 shows our assumptions on how each company's generation mix could shift, in line with the carbon-altered generation technology economics, as carbon prices rise to  $\pounds$ /tonne CO2e and  $\pounds$ 15/tonne CO2e (the first two switching points)

We have assumed each firm adds the following renewables capacity at the appropriate carbon price: *SP* adds 1000 MW of onshore wind capacity and 1500 MW offshore wind; *SSE* adds 1000 MW onshore wind; *Endesa* adds 2000 MW wind (on- or offshore) and 1000 MW biomass; *Iberdrola* adds 4000 MW wind; *RWE* adds 2000 MW offshore wind; *E.ON* adds 2000 MW offshore wind and 1000 MW biomass; *MVV* adds 1000 MW offshore wind; and *Enel* adds 1000 MW onshore wind and 500 MW biomass. These are aggressive assumptions that are based broadly on the current size and level of existing investments already directed towards renewables by each firm, and any objectives stated with respect to future expansion of renewables activity.

<sup>&</sup>lt;sup>5</sup> This range of carbon prices and abatement assumptions is believed to encompass the breadth of predictions made by various authoritative studies conducted on the emissions trading markets (including those by McKinsey, UBS Warburg and the Royal Institute of International Affairs).



Figure 5. Potential Switch in Generation Mix Between Fossil Fuels and Renewables with Rising Carbon Price for European Companies

Source: Innovest/Company Reports

## UNITED STATES

The lack of federal constraints on greenhouse gas emissions and the Bush Administration's rejection of the Kyoto agreement means that the primary driving forces behind U.S. power sector  $CO_2$  emissions regulation over the near term are at the state level, and in relation to international assets (specifically, those in Canada and the EU).

There are, however, several initiatives currently underway in Congress to develop regulatory instruments that limit greenhouse gas emissions from the power sector. In addition, all leading Democratic presidential candidates have said they favour rejoining the international climate negotiations and some have either introduced or supported bills with mandatory caps on  $CO_2$  emissions. It seems plausible, therefore, that some form of  $CO_2$  regulation will be targeted at the U.S. power sector in the coming years, and possibly as early as 2005.

In view of these uncertainties, 3 scenarios have been modeled for the U.S.-domiciled companies - AEP, Duke Energy and Southern - plus Pacificorp/PPM (part of Scottish Power) and TransAlta U.S.:

• Business As Usual scenario (BAU), in which only domestic and international GHG regulations currently in place in the U.S. and, for AEP's UK operations, the EU apply<sup>6</sup>.

<sup>&</sup>lt;sup>6</sup> Information on state-level activities in GHG regulation and renewable energy incentives can be found at <u>www.panda.org/powerswitch/finance</u>

- *Moderate Reductions Scenario*, in which CO<sub>2</sub> emissions from generators in the U.S. are reduced to 2005 levels by 2010 and 2000 levels by 2015. Assuming that without abatement initiatives company emissions would grow in line with the U.S. Department of Energy's sector predictions, we estimate the annual abatements required to meet these targets at AEP, Duke, Southern and Pacificorp would be *ca*. 2.1 million tonnes, 0.7 million tonnes, 1.8 million tonnes, and 0.5 million tonnes, respectively.
- *More Significant Emissions Reductions Scenario*, in which CO<sub>2</sub> emissions are reduced to 2000 levels by 2005 and 1990 levels by 2012. Assuming corporate emissions trajectories are the same as for the entire power sector, each firm's overall abatements to 2012 would need to total an amount equivalent to approximately 23% of 2002 levels for these targets to be reached.

In the interests of analytical consistency, for the moderate and more significant abatement scenarios we assume a mandatory domestic emissions cap and trade scheme is in place (as several congressional bills allude to), and, in order to model the two extremes of cost allocation, 95% and 0% grandfathering of emissions is granted (a number of U.S. legislative proposals envision limited use of emissions grandfathering). Marginal generation in U.S. markets is also assumed to be entirely gas-based. For AEP's UK operations, we assume a 50/50 split between gas and coal at the margin under lower carbon prices, changing to gas only above a C price of 15/1000 control to the second secon

As the carbon prices rise, the options open to companies for shifting from high- to low-carbon intensity generation mix under the moderate and more significant scenarios are illustrated in Figure 6. Note that these fuel mix shifts relate to what rational companies could justify economically on an aggregate basis across all operations on account of the carbon price premium, not necessarily what they will do. The age of individual company plants, their level of efficiency and their current estimated retirement dates have not been assessed.

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#### MODERATE SCENARIO

#### MORE SIGNIFICANT SCENARIO

Figure 6. Potential U.S. company switch in generation mix between 2002 and 2015 under moderate and more significant abatement scenarios

#### Source: Innovest/Company Reports

The assumptions build in a substantial expansion into renewables technology under the more significant reduction scenario, in which Duke adds 2000 MW biomass and 1500 MW wind by 2020, AEP adds 2000 MW wind in the UK, 1000 MW biomass in the U.S. and 2000 MW wind in U.S. by 2020, and Southern adds 1500 MW biomass by 2020. We assume that Duke's renewables additions come in part due to incentives in California and New England. Similarly, AEP's U.S. renewables investments are assumed to arise from green power incentives in Texas, with some additional investment in Ohio. Southern's biomass

plants are assumed to be linked with federal programs to boost cogeneration and biomass investments. Again, these assumptions are based broadly on renewables objectives outlined by each firm or opportunities available due to a presence in states offering renewables incentives.

The U.S. situation is complicated by two factors above and beyond the abatement scenarios:

• The level of power market regulation, and the role of the Federal Energy Regulatory Commission (FERC) and the Public Utilities Commissions (PUCs) in setting wholesale power prices.

The financial calculations presented here have not been modified to account for any position that the regulatory agencies may take in factoring carbon-related costs into the rate-based returns for the regulated assets of the U.S. companies. The analysis therefore presents a straightforward view of the U.S. companies' cost burden owing to  $CO_2$  prices, without distinguishing between regulated and deregulated assets, and the possible net impacts were these firms to attempt to pass on these costs as in a competitive market situation.

• The existence of legislation to combat other forms of airborne pollution.

This report recognizes that the relationship of  $CO_2$ -driven policy developments with other pollutant legislation in the U.S. (particularly the SOx and NOx programmes in the Northeast, and the mercury emissions regulations, for which a proposed rule is expected in December 2003 and which will require compliance by year-end 2007) may also affect the fuel-switching decisions. Carbon-related costs linked to shifts in fuel mix away from coal could be overstated where shifts may have already occurred due to other compliance efforts, such as those required for reducing mercury emissions. Conversely, capital spent on mercury compliance alone – for instance installing a scrubber instead of fuel switching - may be inefficiently allocated if future actions to reduce  $CO_2$  emissions are also required. In this case, where a company invests in reducing mercury emissions only, and later invests in reducing  $CO_2$  emissions, the total financial impact will be greater than the carbon costs reported here. We note that AEP and Southern have the highest mercury emissions in the U.S. power sector.

## CANADA & JAPAN

Governments in Canada and Japan have ratified the Kyoto Protocol and are developing domestic action plans to meet their obligations under the treaty. Currently, the emissions reduction targets that industrial emitters, including the power sector companies in this survey, will have to meet, and the conditions under which they will be pursued, are unspecified. However, we note the following as being relevant to the financial impacts of these future abatement responsibilities:

• In **Canada**, where large industrial emitters are forecast to contribute almost 50% of industrial emissions by 2010, emissions reductions targets are being established through negotiated covenants. Large industrial emitters (LIEs) will be asked to reduce emissions by 55 million tonnes below a business as usual trajectory by 2012, according to Environment Canada. In response to industry concerns over negative impacts, the government has said that it will provide protection against risks associated with high carbon costs in the form of a cap of C\$15 (⊕.50, US\$11) /tonne CO<sub>2</sub>e on the price big companies will have to bear. The plan will also set a target of 10% of new electricity generating capacity from emerging renewable sources.

According to Canada's GHG Emissions Summary<sup>7</sup>, the electricity and heat generation business produced 95.3 million tones of  $CO_2$  in 1990, 101 million tonnes in 1995, 136 million tonnes in 2000 and 137 million tonnes in 2001. Assuming that growth continues at this pace, we estimate that by 2012  $CO_2$  emissions would reach approximately 155 million tonnes. The thermal electricity generation sector contributes 40% to the LIE group's emissions as a whole; given that LIEs will be asked to cut emissions by 55 million tonnes, we assume that the power sector will be asked to cut emissions by 40% of 55 million tonnes, i.e., 22 million tonnes. This constitutes a cut

<sup>&</sup>lt;sup>7</sup> Found at http://www.ec.gc.ca/pdb/ghg/documents/tables/canada\_2001\_e.pdf

of some 14% below projected BAU emissions and 16% below 2003 emissions (assumed to be 140 million tonnes). In view of this, we base our analysis on a scenario in which TransAlta will need to cut its emissions by 10% and 20% below 2003 levels by 2012, and that prices range up to C\$15 ( $\oplus$ .50, \$11)/tonne CO<sub>2</sub>e), as per the government's price limit. In the interests of consistency, we also assume a national cap and trade system and a 95% grandfathering allocation approach in our base case.

• In **Japan**, electric utilities are being asked to reduce CO<sub>2</sub> emissions intensity by approximately 20% from 1990 levels, from 0.38 kg CO<sub>2</sub>/kWh now to about 0.34 kg CO<sub>2</sub>/kWh. This represents an intensity reduction of 10.5% below 2002 levels. Overall, electricity consumption is expected to increase by 43% over 1990 by 2010, however, the increase in total CO<sub>2</sub> emissions is projected to increase by only 14%. Critical to the Japanese plan to reduce emissions will be the role of nuclear and CCGT. However, after the recent safety troubles surrounding the Japanese nuclear industry, public opposition to nuclear power is running high.

Our assumptions of generation mix changes that could occur as a result of rising carbon prices at the three firms in question are as follows:





Source: Innovest/Company Reports

In terms of renewables investment, we have assumed that TransAlta adds 2000 MW of onshore wind, Tepco adds 1500 MW of wind and Kansai adds 1000 MW of biomass.

For Tepco and Kansai, the annual abatement requirements have been estimated from the overall emissions abatement target of the Japanese electric utilities sector as a whole. If we assume Kansai and Tepco will be required to cut their carbon intensity to similar levels – i.e., they have target 2010 intensities of 0.23 million tonnes  $CO_2/TWh^8$  and 0.26 million tonnes  $CO_2/TWh$ , requiring annual abatements of 0.16 million tonnes and 0.39 million tonnes, respectively.

<sup>&</sup>lt;sup>8</sup> Note: 1 TWh = 1,000,000 MWh

The impacts of these intensity reduction requirements are estimated at carbon prices of \$5, \$10 and \$25, which can be broadly associated with the periods 2004-2005, 2005-2008 and 2009-2012, under the 95% grandfathering assumptions.

#### CROSS-REGIONAL COMPANY COMPARISONS REVEAL RELATIVE EXPOSURE

Bringing these various regional scenarios together into a single matrix, we can identify three general scenarios common to each of the regional analyses that correspond to the following scenarios:

- 1. **'Soft' carbon pricing conditions**, in which carbon prices range from €3.5-4.5 (\$4-5) and abatement amounts are assumed to be in the region 5% below 2002 levels (n.b., for U.S. companies, the corresponding 'business as usual' scenario means that only Duke has short term obligations to cut emissions, to approximately 0.6% below 2002 levels by our estimates of state initiatives. AEP's voluntary commitments to reducing emissions 4% between 2003 and 2006 with the Chicago Climate Exchange have not been factored into the analysis). We anticipate that these conditions could broadly correspond to the period up to 2005.
- 2. **'Moderate' carbon pricing conditions**, in which carbon prices range from €8.5-13 (\$10-15) and abatement amounts are in the region 10% below 2002 levels. We anticipate that these conditions could broadly correspond to the period up to 2007/8. Note that for the U.S. companies, this corresponds to the 'moderate' scenario in which the assumed abatement would be the equivalent of some 8.5% of 2002 emissions levels.
- 3. **'Significant' carbon pricing conditions**, in which carbon prices range from €17-22 (\$20-25) and abatement amounts are approximately 20% below 2002 levels. We anticipate that these conditions could broadly correspond to the period up to 2012. Note that for the U.S. companies, this corresponds to the 'more significant' scenario in which the cumulative abatement by 2012 is assumed to be equivalent to 23% of 2002 levels.

The analysis is presented in two stages. First, we estimate the additional marginal generation costs borne by each firm across its portfolio at carbon prices corresponding to the 3 scenarios described above. This presents, in effect, the worst-case cost burden for each of the firms. At present, the extent to which these costs will need to be absorbed by each company as opposed to being passed on the consumers (or even upstream to fuel suppliers) is a significant uncertainty. We therefore model the net impacts assuming an entirely competitive power market, in which these costs can be partly passed on to the wholesale market subject to the constraints described earlier.

In each instance, we examine a situation in which each firm's generation mix stays unchanged from 2002, and one in which a switching scenario takes place, where the fuel mix changes gradually from coal to gas and renewables according to the new technology hierarchy. We also model the sensitivity of these net financial impacts to an increase in natural gas prices relative to coal, and to a 0% grandfathering allocation method.

## 4. WINNERS AND LOSERS IN THE EMISSIONS RACE

#### COSTS COULD BE SUBSTANTIAL, DEPENDING ON METHOD OF RIGHTS ALLOCATION

The additional marginal generation costs that each firm would incur due to its fossil generation (based on 2002 output) are shown in the following table. Costs are provided for two different grandfathering scenarios: 95% and 0% grandfathering. In each case, we identify costs under a no-switch situation and under a fuel switch scenario at three carbon cost points: 5 (\$5.75), 10 (\$11.50), and 20 (\$23)/tonne CO<sub>2</sub>e:

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Table 2. Increase in marginal fossil fuel generating costs at €5, €10, and €20/tonne CO<sub>2</sub>e. Source: Innovest

These costs are expressed as a percentage of 2002 earnings before interest, taxes, depreciation and amortisation (EBITDA) in the summary figures below.



Figure 8. Additional generation costs at rising carbon prices under 95% grandfathering.

#### Source: Innovest

Under a 95% grandfathering scenario, TransAlta faces the greatest costs. Because its carbon cost is capped by the Federal government at ca.  $\textcircledlo$  (\$11.50)/tonne CO<sub>2</sub>e, its costs are limited to a maximum of  $\pounds$ I4.8 (\$17 million), or just over 15% of 2002 pre tax earnings. E.ON and Scottish Power are the most exposed European companies, each facing costs equal to approximately 9% of 2002 earnings at  $\pounds$ 20 (\$23)/tonne CO<sub>2</sub>e. Notwithstanding the greater uncertainties in the U.S., of the three U.S. based companies AEP has the greatest exposure under each price scenario, with additional costs of up to 8.5% of 2002 EBITDA at only  $\pounds$ 10 (\$11.5)/CO<sub>2</sub>e.

A similar result emerges under a 0% grandfathering situation, although the numbers are significantly inflated as might be expected. We note that even with a fuel switch, the additional costs are significant, however, the benefits of switching in terms of reduced cost exposure are also substantial.



Figure 9. Additional generation costs at rising carbon prices under 0% grandfathering.

#### Source: Innovest

By switching, all firms reduce their cost burden as might be expected (Figure 10). In terms of euros 'saved' by switching, RWE and AEP have the greatest incentive to switch because of their considerable fossil fuel generation dependency (particularly coal), although only RWE is likely to pursue such a strategy under current regulatory conditions. AEP's regulated rate-based situation means that it does not face the same incentives as its European counterparts. In each case, rational fuel switching under a  $\notin 20$  (\$23)/tonne CO<sub>2</sub>e price regime could reduce costs by approximately  $\notin 40-50$  (\$46-58) million. Southern, Scottish Power, Duke, Endesa, Enel and E.ON could see cost reductions of approximately  $\notin 15-20$  (\$17-23) million each. SSE and MVV have very little incentive to switch, because of their relatively clean fuel mix.



Figure 10. Benefits of fuel switching at €20/tonne CO<sub>2</sub>e for 95% and 0% grandfathering scenarios. Source: Innovest

What magnitude of emissions reductions can be achieved under these scenarios? In our models, we see substantial abatements associated with the fuel switch (Figure 11).



#### CO2 EMISSIONS ABATEMENTS OBTAINABLE VIA FUEL SWITCHING

Figure 11. CO<sub>2</sub> emissions reduction possible under the three carbon pricing scenarios.

#### Source: Innovest

These results imply the following regarding the overall effect of pricing carbon:

- Even at modest carbon prices (in the region of €15 (\$17.8)/tonne CO<sub>2</sub>e), substantial emissions abatements, in excess of 250 million tonnes across all companies, are possible through fuel switching. EU company abatements at this price total 70 million tonnes, almost 10% of the entire power sector's CO<sub>2</sub> emissions in 2002.
- Changes in relative fossil fuel prices (coal and gas) do not affect the amount of abatement possible, only the price at which they can be obtained; the net financial impact of even a €2 (\$2.3) increase in natural gas prices can be significant for some companies; however, increasing total costs by anywhere between 5% and 25%. Scottish Power and, most notably, RWE are most sensitive to rising natural gas prices under the significant carbon-pricing scenario.
- The method of allocating emissions rights is extremely important in determining the net financial impact on companies. As the percentage of freely allocated grandfathered emissions rights increases, the impact on earnings (both positive and negative) is generally exaggerated. However, the extent of grandfathering has no influence on the abatements that can be achieved by fuel switching.

#### NET IMPACTS WILL BE MOSTLY POSITIVE UNDER PURELY COMPETITIVE CONDITIONS

The net financial impacts (expressed as a percentage of 2002 earnings) for each company are compared in the following summary charts, which cover a 95% grandfathering scenario (with and without fuel switch), and a 0% grandfathering scenario (with and without fuel switch). Note that in the charts below, a positive number corresponds to a net financial gain for the company; a negative (below x-axis) number corresponds to a net financial loss.



Figure 12. Net impacts as % 2002 EPS at rising carbon prices with and without fuel switch under 95% grandfathering scenario.

Source: Innovest



Figure 13. Net impacts as % 2002 EPS at rising carbon prices with and without fuel switch under 0% grandfathering scenario.

Source: Innovest

The results for each company – summarised above - indicate that<sup>9</sup>:

• The net financial impact of carbon costs will actually be positive for many firms, even under a business as usual generation mix scenario, because of market liberalisation forces. However, all companies gain by engaging in fuel switching, regardless of the business-as-usual impacts.

• The biggest winner under every scenario considered is E.ON, primarily because of the high windfall gains. Net impacts are over 100% 2002 earnings; by fuel switching, this figure rises to over 200%. The possible costs arising from Powergen's (owned by E.ON) U.S. coal operations' need to reduce emissions have not been factored in, although we expect that these will not significantly alter the results.

• Under a business as usual (i.e., no fuel switch) scenario, Scottish Power, SSE and RWE will face the biggest financial challenge in the EU depending on which emissions allocation approach is used.

• In the U.S., Southern and AEP are the most at risk, although clearly the extent to which these additional costs will be reflected in the wholesale power market by FERC is an unknown. The outcome of carbon management issues at Pacificorp will have a substantial bearing upon the overall impact of climate policy matters on Scottish Power.

• As a result, Scottish Power, TransAlta and AEP have the most to gain by switching to a slightly less carbon-intensive generation mix. The coal-intensive companies – AEP, SP, Southern and TransAlta – also have the most to gain from maximizing the grandfathering of emissions rights.

• Kansai and Tepco both emerge net winners assuming they can pass costs on to the market. The benefits of fuel switching are lower for these firms than for their North American counterparts, because of their low coal dependency and higher gas prices.

• The price cap of C15/tonne CO<sub>2</sub>e on TransAlta's abatement costs reduces the firm's losses under a no-switch scenario, but could also reduce its gains by impeding the firm's transition to a cleaner generation portfolio.

• Of the two Spanish utilities analysed, Iberdrola is in by far the better position under a no-switch scenario due to its less carbon intensive fuel mix. However, Endesa appears to gain more from fuel switching, particularly if the output from its non-fossil fuel facilities can be increased.

# ULTIMATELY, THE BIGGEST UNCERTAINTY IS OVER HOW THE COSTS OF REDUCING $\text{CO}_2$ emissions will be shared

The total additional carbon-related costs faced by each firm and the net financial impacts that could arise under competitive market conditions represent the two extremes of possible impacts on shareholder value for the companies in question. The former corresponds to the greatest potential financial burden the power firms would have shoulder; the latter, the magnitude of the potential gains available. Questions remain, however, over how policymakers and regulators will ultimately treat the compliance costs: Will power companies be forced to bear all of the costs associated with carbon, in accordance with the polluter pays principle of European environmental law? Will energy market regulators allow wholesale power prices to rise on account of carbon, such that consumers bear the brunt of the impact? Given the trend towards power market deregulation/liberalisation, what mechanisms will regulators deploy if they do decide that intervention is necessary? And how can the differential competitive conditions created by the carbon price be harnessed to spur genuine innovation to increase value, as opposed to redistributing it?

As the situation becomes clearer, we hope that the central findings of this study - that there are many options available to the utilities to deal with the impact of increasing prices on  $CO_2$  emissions; that doing nothing is the worst option; and that by making astute changes to the fuel mix and investments to refurbish

<sup>&</sup>lt;sup>9</sup> Further information on these results and background information can be found at <u>www.panda.org/powerswitch/finance</u>.

existing assets, profits may well increase - will provide a useful touchstone for assessing the impacts of rising carbon prices on the power sector.

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# **ACKNOWLEDGEMENTS**

The authors wish to thank Climate Change Capital for advice and technical input during the preparation of the report, and the following external reviewers for providing valuable comments:

Daan Dijk, Manager, Sustainable Energy and Environmental Markets, Rabobank

Richard Hunter, Managing Director, Global Power, FitchRatings

Lawrence H. Linden, Advisory Director, Goldman Sachs & Co.

Nick Robins, Head of SRI Research, Henderson Global Investors Ltd.

Tessa Tennant, Chair, Association for Sustainable and Responsible Investment in Asia (ASRIA)

Review of the report does not imply endorsement – personal or institutional - of its content or findings. The information and opinions contained in this report are the sole responsibility of the authors and WWF.

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With **PowerSwitch!**, WWF challenges the power sector - the companies producing electricity and the people in finance and politics guiding their decision-making.

The power sector should become CO2-free in developed countries by mid of this century, and make a major switch from coal to clean in developing countries.

There's no shortage of solutions - we've just got to do it.

http://www.panda.org/powerswitch