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Abstract

The purpose of this deliverable is to discuss the issues arising from the fact that a demonstration HYPOGEN plant has a novel risk profile, both technically and commercially.

The report takes an overview of this risk profile and focuses on those areas of risk that are beyond those that are similar to other power stations. These are then explored in some detail and with analysis of possible ways to mitigate the risks. Possible solutions to allow the plant to be financed are developed to show likely details together and their expected effectiveness. These solutions are categorised as being of political / regulatory in nature, private sector commercial or requiring public sector support.

Key conclusions are produced indicating areas where action and clarity are needed to achieve a lowest-cost route forward.

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1 INTRODUCTION

This document is one of a series looking at the financial aspects of the design of a HYPOGEN plant. Reference is made throughout to the relevant DYNAMIS documents which provide and support these recommendations; they are identified by their Dx.y.z number and identified fully in the Reference section below. Some DYNAMIS reports have a restricted dissemination level, but are available to eligible parties in the DYNAMIS project eRoom or from the project coordinator.

1.1 Background

The issues discussed in this report build on aspects raised in a number of previous deliverables. In D6.2.1 the technical and operational risks associated with a HYPOGEN plant are raised in the context of the ability to raise finance for such a plant; various possible solutions are discussed. These aspects are discussed in more detail in D6.2.2, with a focus on those technical solutions being proposed within the DYNAMIS project.

The issues relating to the value of carbon and incentives arising from the current EU Emissions Trading Scheme (ETS) and National Allocation Plans (NAP) are raised and discussed in D 6.1.3 and are also discussed in the context of the potential role of the EIB in D6.2.3.

This report takes an overview of the risk profile of a HYPOGEN plant and focuses on those areas of risk that are novel to its design. These are explored in some detail and some conclusions are drawn about possible ways forward and their likely effects.

1.2 Utility Approach

In the supply of electricity and, particularly in the decisions relating to power station investments, the boards of utility companies are likely to take a predominantly risk-averse approach. This is for two key reasons:

- power stations represent a very large and long-term (25 years or more) investment and there is an ever-present risk of a stranded asset;
- electricity supply in Europe, from which is derived the majority of revenues to support such an investment, is a competitive business (or at least pseudo-competitive through EU Directives and regulation) from which a non-commercial rent cannot be extracted.

Hence shareholders in utility companies will be best served by investments in the most competitive sources of power, given all the costs and risks. Strategies of investing in power plant which are well-proven and similar to competitor companies will show the lowest overall risk profile.

1.3 Political Direction

The EC is endeavouring to address the problems of climate change by altering the behaviour of companies and individuals in their approach to energy and particularly the emission of carbon di-oxide to the atmosphere. Low-carbon or renewable power sources do not necessarily meet the low-risk strategies favoured by utility companies, as discussed above, especially for power station investments of considerable size.

Hence there is a very significant mis-match between the natural commercial behaviour of the utilities and the political strategy being adopted. This leads to the need for political action to address this gap. Possible routes to achieving this are discussed in Section 3 below.

It is vital that this strategy gap is addressed in a clear and robust way if we are to see investment in HYPOGEN-type plant and avoid considerable investments across Europe in plant which leave a long-term legacy of high carbon emissions and which will be very costly to alter. It is also clear that the mechanism chosen to address this gap should not only support a HYPOGEN demonstration plant but also support subsequent decisions to invest in similar plants if the technology is to prove successful. The correct political messages can achieve a sea change in strategy at least cost, both in terms of the net present value (NPV) of actual power plant costs, but also more widely in the achievement of cost-effective mechanisms for carbon emissions reductions.

2 KEY HYPOGEN RISKS

A future HYPOGEN plant has a novel risk profile when compared to a conventional power plant. Within the one facility, it would need to integrate revenues from hydrogen sales, electricity sales and carbon dioxide capture (if relevant). The additional investment costs and operational costs associated with carbon dioxide capture, conditioning and transportation will also need to be recovered.

2.1 Reference Plant

In order to assess those risks that are novel, a baseline reference plant has to be identified from which the changes or extensions to risk are evaluated. This reference plant would normally be defined as the standard equivalent plant, using the same fuel feedstock, which would be the default investment choice of a utility company given the current state of EC policies and regulation framework and within the current commercial environment. This reference plant is also important as the baseline for assessing additional costs – see Section 2.5 below

For the purposes of this report, reference plant are taken to be as follows:

Table 2.1.1 Reference Plant

Fuel	Plant
Natural Gas	CCGT with no carbon capture
Coal / Lignite	IGCC with no shift or capture

The reasons for this choice are as follows:

- Current EC / MS policy on future requirements for carbon capture are not clear and do not provide a sufficiently clear or close target to justify the additional investment of capture equipment;
- The value of carbon within the EU ETS is not currently sufficiently high, nor is there sufficient confidence that it will be in the future, to provide an income stream that would support the costs of carbon capture.

These issues and how they might change in the future are discussed further in the section on risk mitigation (Section 3 below). However, it is important to note here that changes to legislation and regulation, including how firm it is, will change the effective reference plant and hence the risks and magnitude of costs that are considered novel or additional– see Section 3.2.

Given these reference plant, the “standard” risks can be identified and hence the additional risks can also be categorised. This is done below and the key risks are also shown on a power station project diagram in Appendix 1.

2.2 Risk Catalogue

Those key and novel risks associated with a HYPOGEN plant can be categorised as shown below. A possible mitigation route is also shown in each case. Many of these approaches are standard in the power industry and are not discussed further in this report; those that are novel or whose mitigation may require an unconventional approach are highlighted in the table and are discussed further below.

Table 2.2.1 Power Plant Risk and Mitigation

Risk	**Possible Mitigation**
Technical	
Individual Component "Island" technical operation	Manufacturers' technical guarantees
Complete process functional operation	EPC[1] (or supplier) guarantee wrap
Performance Efficiency & Output	Completion guarantee / performance test
Performance Reliability	Technical guarantees / extended test / maintenance contracts / LDs
Construction delay	Completion guarantees
Commercial	
Power Income stream	Offtake agreements, escalation
CO_2 Income stream	CO_2 price (with support?)
Hydrogen Income stream	Power substitution offtake
Fuel cost escalation	Power escalation mirror / fuel substitution
Operational	
CO_2 physical disposal / storage	Physical store or pay agreement?
CO_2 volume shortfall	Operational guarantees
Financial	
Capital Cost of Capture technology	CO_2 price (support) and/or tax incentive?
Social / Political / Legal	
Legal & Licensing regime	Gov't action / EC support
CO_2 Storage public acceptability	Gov't support; local community support; communication programme

[1] Engineering, Procurement and Construction contractor

2.3 Additional Risks

The capture and storage of carbon dioxide requires considerable additional equipment when compared to the reference plant. At a basic level, this involves three elements:

- the capture equipment (including conditioning and compression),
- the transportation pipeline,
- the storage facility.

Taking these in turn, the capture equipment involves additional capital costs and some different technical processes compared to the reference plant, but the type of risks involved and the way these should be handled are similar to the standard ones. Support for the additional capital costs and the reliability of the revenue stream supporting the costs of capturing CO_2 are discussed further in Section 3.

The CO_2 pipeline is a novel element when compared to the reference plant and the particular risks are discussed below.

The storage facility (which may be an aquifer or an oil or gas field) has characteristics and a risk profile that are entirely different to those of a power station. Because of this, it is anticipated that injection and storage of CO_2 would be part of a separate commercial identity with the skills to manage and charge out for the relevant risks; discussion of these risks are not included in this report.

2.4 Risks involved in CO_2 Pipeline

The CO_2 transportation pipeline is in essence a standard piece of infrastructure and could be expected to generate a modest rate of return and have a steady low-risk income that supports this. However, there are other risks associated with the throughput of CO_2 that need to be addressed. In order to look at these, a split of functions between a Power company, a Pipeline company and a Storage company has been assumed in the simplified diagram below.

If there is no flow of CO_2 through the pipeline, the infrastructure still needs to make a return to service the financing and hence the most likely form of tariffs are capacity-related where payment is made irrespective of flow. This means that the Pipeline company is only taking the breakage / blockage risk that the physical pipe is unusable.

In this case, the power company has paid for capacity in the pipe and takes the risk that this cost is not supported (effectively a stranded additional asset). This shortfall may be against initial / continuing funding of the additional capital costs or a shortfall in expected revenues. If the station is not running or not capturing / conditioning CO_2 and the income is from a commodity value on captured CO_2 then there is a shortfall in income – a CO_2 volume risk. If the value of carbon is not high enough to generate enough unit income this is a CO_2 price risk.

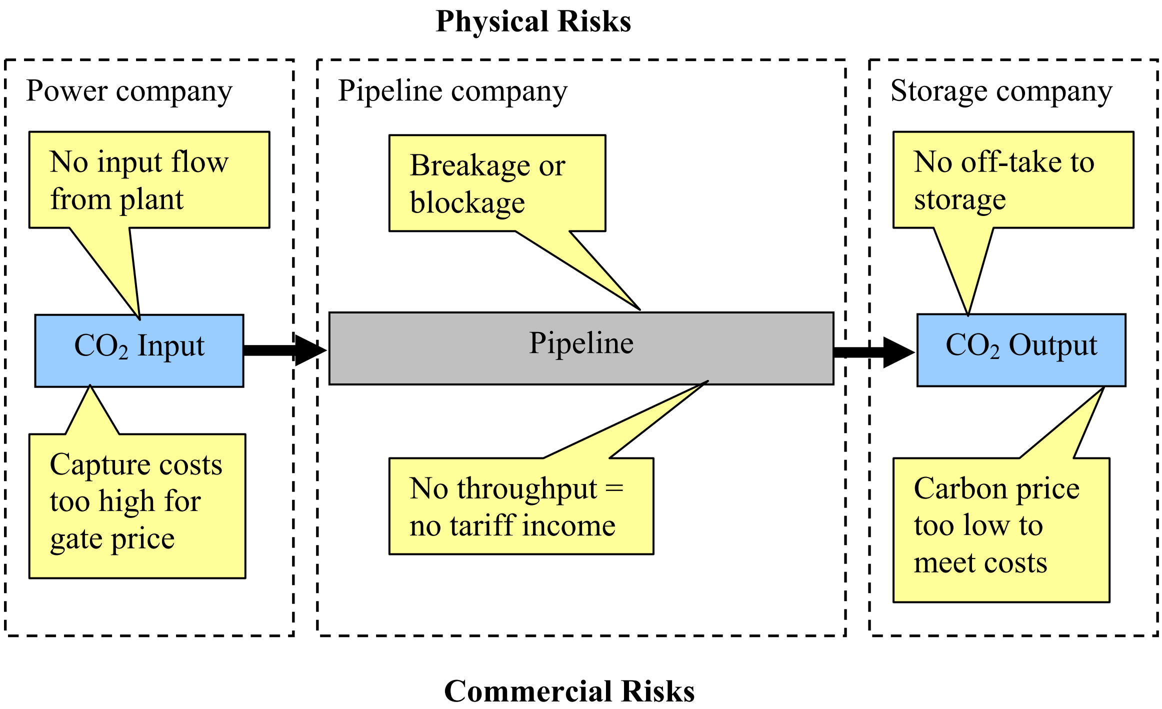

Figure 2.4.1 Pipeline Risk Diagram

The Storage company may be expected to be taking any CO_2 which passes through the pipeline. Again, assuming a commodity-related payment for CO_2 storage, there is a volume risk of reduced or no CO_2 flow and a price risk which is again driven from the value of carbon.

Hence the two key elements of income risk are the level of initial funding and the continuing carbon price. There is also a captured volume of CO_2 risk, but this is essentially a plant performance issue and should be covered by similar technical / performance guarantees to those for the rest of the plant.

2.5 Magnitude of Risks

In order to make an assessment of the magnitude of the main financial risks, it is necessary to:

- Identify the relevant reference plant
- Evaluate the benchmark capital and operating costs associated with the reference plant
- Assess the additional capture and operating costs of the HYPOGEN plant technology

Reference Plant

As discussed above (section 2.1), the identification of the relevant reference plant is critical to any discussion of additional risk and cost. In the current EC policy climate the most likely reference plant will have no carbon capture at all and it can also be argued it would not contain a shift stage in the syngas process (coal / lignite) because this would be unnecessary.

Arguments have been made elsewhere that the reference plant for all plant including coal / lignite should be a natural gas CCGT, being the least-cost new-entrant. On purely academic economic grounds, there is an argument for this approach (best new entrant cost), although in the last two years CCGTs have been more expensive to operate than coal plants in many countries (eg the UK). It is also a much more difficult comparison to make using s lifetime levelised electricity price calculations, requiring a lot of assumptions, and it ignores fuel diversity / security and other issues.

Hence, for the purposes of this report, the current reference plant for gas is taken as the CCGT (no capture) and for coal and lignite it is the IGCC with no shift or capture.

Capex and Opex

Capital cost (capex) levels for power plant have escalated considerably in recent years, driven partly by the increases in the price of steel due to Far East demand. Hence it is important when comparing costs to use costs which are either from a comparable date or which are corrected by an appropriate index.

Operating costs (opex) are more difficult to derive and have been estimated by using an overall average figure of 3% of capital plant costs plus an adjustment for changes in overall plant efficiency (and hence fuel opex) in the inclusion of capture equipment, CO_2 pipeline and storage facilities. This approach has also been checked by ensuring consistency of overall project returns from plant financial models.

The following capital costs (table 2.5.1) for new fossil-fuel plant with and without pre- and post-combustion capture of CO_2 are those quoted recently by NETL[2] and also those derived using the PPAP model in D2.4.3.

Table 2.5.1 Capital Costs

Plant Type	**Fuel**	**Capture**	**Capital Cost €/kW**	
			NETL	**PPAP**
CCGT	Natural Gas	None	402	
		Post	850	1250
IGCC (GE)	Coal	None	1314	
		Pre	1733	1942

A number of issues arise from these figures. Firstly, it is worth noting that these are specific (€/kW) capital cost figures and that a large proportion of the increased cost for capture is due to the reduction in plant output.

Secondly, the PPAP costs are higher than the US figures, notably in the CCGT case. This is mainly due to the quoted prices for gas turbines on each side of the Atlantic. The US machines are slightly lower cost and smaller because of the 60Hz (cf 50Hz in Europe) specification, but the main difference seems to be due to the number of machines sold and the consequent pricing.

Again from the NETL report, the CO_2 additional capture costs are calculated for different plant. The method uses the levelised cost of electricity (LCOE) difference and the CO_2 emissions change between the capturing and non-capturing plant as follows:

[2] Cost and Performance Baseline for Fossil Energy Plants, Volume 1, DOE/NET

Equation 2.5.1

$$Avoided\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{Emissions_{w/o\ removal} - Emissions_{with\ removal}\}\ tons/MWh}$$

LCOE takes account of lifetime operating costs, including both additional capital and lower efficiency. The calculated values are quoted as follows:

Table 2.5.2 Additional Capture Costs

Plant Type	CO_2 cost (€/tonne)
CCGT	56
IGCC (GE)	22

These additional capture costs can be broken down into components as indicated above. The largest contributory cost is the loss of efficiency and power output from the plant as a whole when capturing. This includes the power requirement for CO_2 conditioning and compression. Next most significant is the return on the increased capex invested in the capture equipment, the pipeline and the storage facilities. The third category is the increased operating costs of each of the additional components, which has been assumed to be at the generalised figure of 3% of the capex. An assessment of the breakdown of the total capture costs is shown in the pie chart below (Figure 2.5.1).

Once the plant is built, the additional capital costs are a sunk cost and are unaffected by the actual operating regime of the plant. However, if the plant is operated in non-capture mode, the power reduction and efficiency effects are largely reversible and most of the opex would be saved if this were over an extended period. This means that the permanent additional costs are around 48% of the total with the other 52% being incremental. Hence there is a risk mitigation route for half of the additional costs in not running the capture cycle if in the event throughout the lifetime of the plant there is no economic case for doing so.

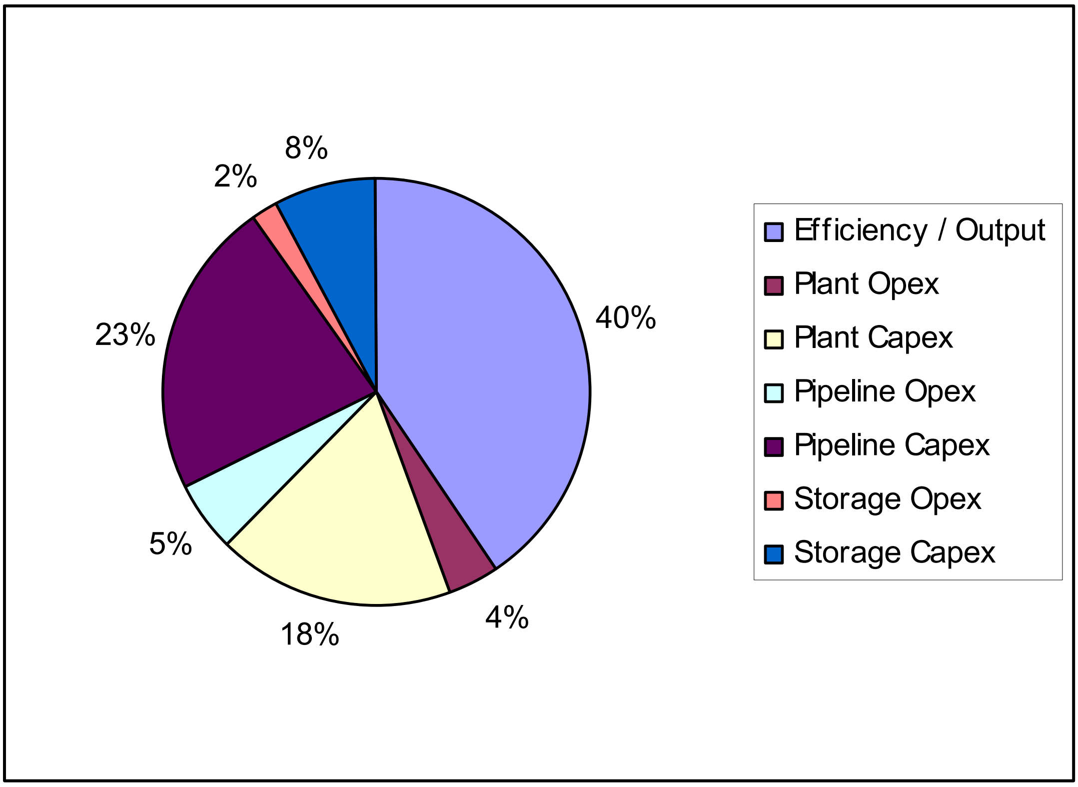

Figure 2.5.1 Breakdown assessment of CO_2 capture costs

3 RISK MANAGEMENT POSSIBILITIES

This section discusses the novel risks identified above and looks at the nature of the risks and the possible routes to mitigation that could be put in place. Issues arising from these possible solutions are also discussed in terms of their potential positive and negative impacts.

The section is arranged in order to achieve a logical progression from one area to the next. The initial part deals with the policy and legislative framework set by the EC (or Member States as may be the case) and looks at the consequences of possible regimes. This then leads through to a discussion of those commercial (or pseudo-commercial) contractual arrangements that are possible under the policy scenarios and then the remaining funding gap(s) can be identified as requiring some sort of public sector support.

3.1 Funding Sources

There are only two key sources of funding to support the capital investments in power stations:

- revenues from the electricity consumer (including relevant levies)
- revenues (in the form of taxes) or capital support (in the form of grants or tax relief) which derive from the tax payer.

In general, if the cost of the power stations is supported within the general envelope of electricity prices / tariffs then the consumer pays and if not then the taxpayer has to pay. The general principle that the consumer of a good should pay for its costs suggests that in the longer-term the electricity consumer will always pay, but there may be periods where taxpayer support is needed. Funding arrangements are discussed further in 3.4 below.

The suggestion of allocating “free” ETS allowances to eligible plant may appear to be a third source, but in reality if we assume the additional allocation has no perturbing effect on the ETS market, the revenues foregone for the value of these allowances are attributable to the public (taxpayer) as a source (see also 3.4 below).

3.2 Policy / Legislation

As was indicated in section 1.3 above, the introduction of low-carbon generation, and CCS in particular, is a change in strategy for the utility companies that will not be achieved without being directed and underpinned by a change in policy and the associated long-term (around 20 years) regulatory or legislative framework. Utilities will not necessarily be opposed to additional costs in their operations in order to meet climate change goals but need certainty to make the long-term investment decisions and the ability to recover (finance) those costs over the lifetime of the assets.

At the moment this framework consists of an aspirational strategy from the EC for a 20% reduction in emissions by 2020 and a regulatory proposal that all new build plant should be CCS fitted and existing plant retro-fitted for CCS by the same time. As it stands, this leaves utilities with a regulatory vacuum in which to make investment decisions and hence the likely choice of the reference plant indicated in section 2.1 above.

Cost of delay

The issue of delay can be explained by a simple diagram (see below) showing the dates and costs of required levels of carbon capture. In each case the costs will be discounted by the uncertainty in the firmness of the legislation and by a discount rate over the time from investment to the change in regime. In this way an investor can choose to minimise his investment cost. For example in 2012 in the diagram, if there were no legislation in 2020 or the investor didn't believe it was real, cost A with no CCS would be the decision. If the 2020 legislation were certain, cost D (E discounted back to 2012) would be greater than C, so the choice would be to invest in plant with CCS already fitted. On the other hand, if there was some uncertainty about the legislation in 2020, or the investor thought some costs would be picked up at a later date by government, then the discounted price back in 2012 might well fall below C at point B and the decision would be to leave the CCS to be retro-fitted in 2020.

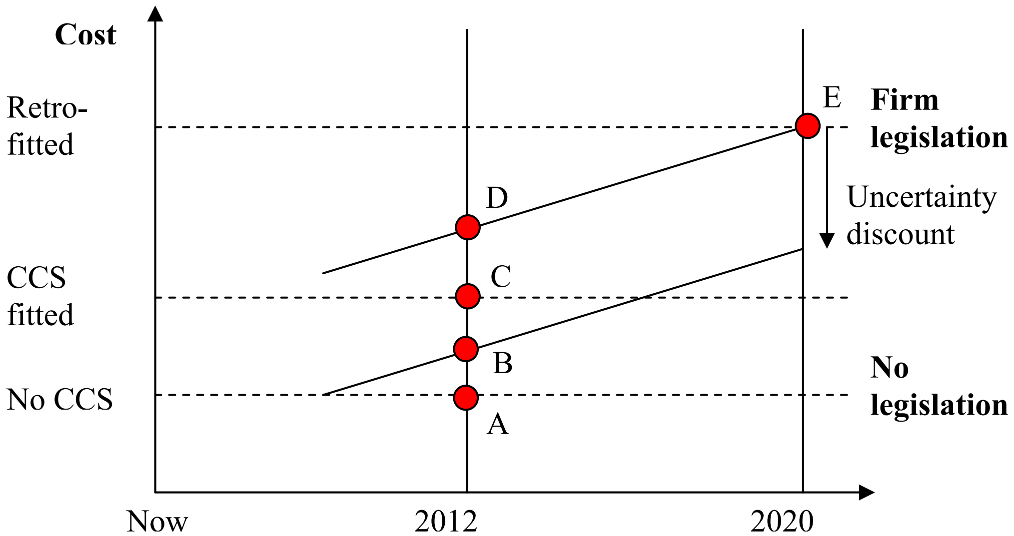

Figure 3.2.1 Cost of Delay

If we assume that all plant will have to conform to CCS by 2020, it can be seen that the least-cost route in general or the public sector (taxpayer) to achieve this is through the construction of compatible plant from the earliest possible date. In this case the consumer starts picking up the full costs earlier as electricity supply prices will include the new investment costs. If all plant is retro-fitted at the last possible moment, this leaves the highest possible potential cost to the public sector (some or all of the A-E difference in the diagram). Hence there is a clear financial incentive on EC and MSs to legislate early and clearly. However, it is recognised that this may be at odds with some of the political pressures on governments.

As already noted the relevant reference plant will change with legislation and so the level of point A and hence the magnitude of magnitude the A-E difference will alter.

Continuity

An important and related issue is one of continuity of policy. If considerable investment by both public and private sector is made in demonstration plant such as HYPOGEN, then the rewards of these demonstrations should be to encourage and facilitate further investments in similar plant more broadly across Europe and developing countries. For this to be the case there needs to be stability in legislation / regulation well beyond the demonstration phase. The threat if this is not the case is a shift in the effective reference plant and the benefits of the technology that has been demonstrated may be effectively stranded. This could also happen with advances in technology, but that process is usually more gradual and better understood by the financial community.

International legal agreements

One of the potential political barriers is the necessity to achieve legal agreements covering international issues on storage of CO_2, particularly off-shore. Considerable progress has been made recently in this area. The London Convention has been modified and agreement has been achieved to modify the OSPAR convention which covers the dumping of waste in or under the sea, although ratification is still outstanding. Changes to this type of legislation to clarify and facilitate the position of CCS can be complex and potentially introduce considerable delay.

National permitting

Each MS has its own arrangements for the range of agreements involved in the permitting of power station developments and associated pipelines etc. It will be necessary to review these and some changes may be necessary if national barriers are to be removed to achieve lowest cost EC carbon capture arrangements.

3.3 Commercial Mechanisms

Given a suitable regulatory framework, there are commercial arrangements that can be put in place to achieve private sector financing of CCS costs. The vital element that can support such arrangements is the value of the carbon which is captured and stored. Any scheme will require confidence from the financial community that the future income stream from captured carbon (or the avoided cost of purchasing carbon allowances) will be sufficient to underpin the additional investment costs and operating costs of CCS.

If these conditions exist, carbon trading companies may well be prepared to provide carbon price swaps, whereby the price received by a CCS plant would be guaranteed at a certain level for a fixed period. Given sufficient confidence, the price and the tenor (length) of the agreement would underwrite the carbon income stream and allow for non-recourse financing of the additional capture costs of a HYPOGEN plant.

The longer-term prospect for the carbon price under the anticipated future EU ETS scheme is good and is very likely to support such investments. Of course, this will only hold true is the accompanying regulatory regime is firm and leak-proof. The period of more uncertainty is the first 5 to 10 years from 2012, when the allocation regime and the NAPs are unclear and may vary between Member States. To cover this period, the European Investment Bank (EIB) has been developing ideas for a seven-year carbon support arrangement, similar to that indicated above, which may benefit from some lower-cost or public funding (see D6.2.3). The current agreed EIB scheme is quite modest compared to the needs of even one HYPOGEN plant, but the arrangement can be expected to be expanded and may well be offered in a similar form by other national / international banks, given a favourable regulatory climate.

3.4 Public Sector Support

If European legislation and regulation fall short of the necessary levels, either in terms of their timing or in terms of the confidence of the international financial community in them, then there will be remaining short- or long-term gaps in the necessary financing for a HYPOGEN plant. These shortfalls will have to be picked up by public sector financial assistance and will require time-limited support arrangements to kick-start the desired change in strategy. This is the current position within the EU because the current uncertainties surrounding the EU ETS arrangements make it currently unbankable as an income stream for projects (see also D6.1.3).

Possible support mechanisms

A number of possible mechanisms have been proposed to provide support for CCS costs. An arrangement could be administered by the EC and applied across the whole of the EU, but this has a number of problems:

- the EU does not have access to the level of funding that is likely to be needed; this probably remains the case even if funds could be geared up through the EIB.
- the NAPs and allocation arrangements for the EU ETS vary by MS
- financial regimes differ across each of the MSs
- the appetite to accommodate such an arrangement also varies considerably by MS

The alternative is for Member States to organise their own support arrangements in a way which is compatible with their national legislation, with those that are the most supportive of the policy taking an early lead. This seems to be what is happening at the moment, but has the disadvantage of being piecemeal and uncoordinated.

Any public support mechanism is likely to need to comply with some overall aims as follows:

a) the public cost is minimised by supporting the most cost-effective proposals
b) the overall EU transition cost is minimised
c) there are cost and confidence benefits derived from the subsidised first-movers for subsequent schemes
d) the cost is limited in amount and bounded in time
e) CO_2 is actually captured and stored in the desired quantities
f) it is compatible with the EU ETS and State Aid rules

Funding Competition

One likely arrangement which has been proposed by, inter alia, the EC and the UK government is a funding competition which would support one or more full-size (eg 400MW as HYPOGEN) demonstration plant on the basis of a lowest cost bid arrangement. This type of mechanism has the attraction of demonstrating it is competitively cost-effective, but could be organised in a number of ways which have advantages and disadvantages. It could take the form of a capital grant / support with the measure being the level of €/kW, or it could be in the form of a carbon price support (€/tonne captured / stored) or a combination of both. Either mechanism would satisfy criteria a) and d) above, but the capital support has the attraction of being short-lived.

A competition for funding could also be arranged in different ways, which have advantages and disadvantages for governments (funders) and developers. Ideally the arrangements should be technology-blind so as to achieve the most cost-effective technology and provide the correct incentives. If the competition screens eligible technologies this could increase confidence for the funder, but may increase costs by excluding good but non-approved technology. Suitable levels of confidence provided by the bidder as part of the submission could be an alternative pre-qualification.

At one end of the scale the competition could be for an upfront capital support (€/kW) which has the attractions of providing a clean competition, but means:

- the developer is left with the cost risk leading to a bidding premium
- there is no cost-discovery for the funder (apart from a ceiling price)
- the support is not linked to carbon actually captured
- the project is left with the funding risk and hence there is a higher chance it may fail.

At the other end of the scale is a competition for on-going support (€/tonne stored) where the price may be bid upfront, but adjusted on an outturn open-book arrangement. In this case

- the funder takes the cost risk and hence the support is not bounded
- there is good cost-discovery to encourage subsequent plant at lowest cost
- the chances of project success are increased because the outturn support is related to actual levels of cost incurred
- the support is linked to and only provided for actual carbon captured.

These pros and cons can be summarised in the following diagram. It is likely that any optimal arrangement is likely to have elements of both types in order to satisfy the criteria a) to e) above. The choice of mechanism will be influenced by many other factors and is unlikely to be uniform across all Member States.

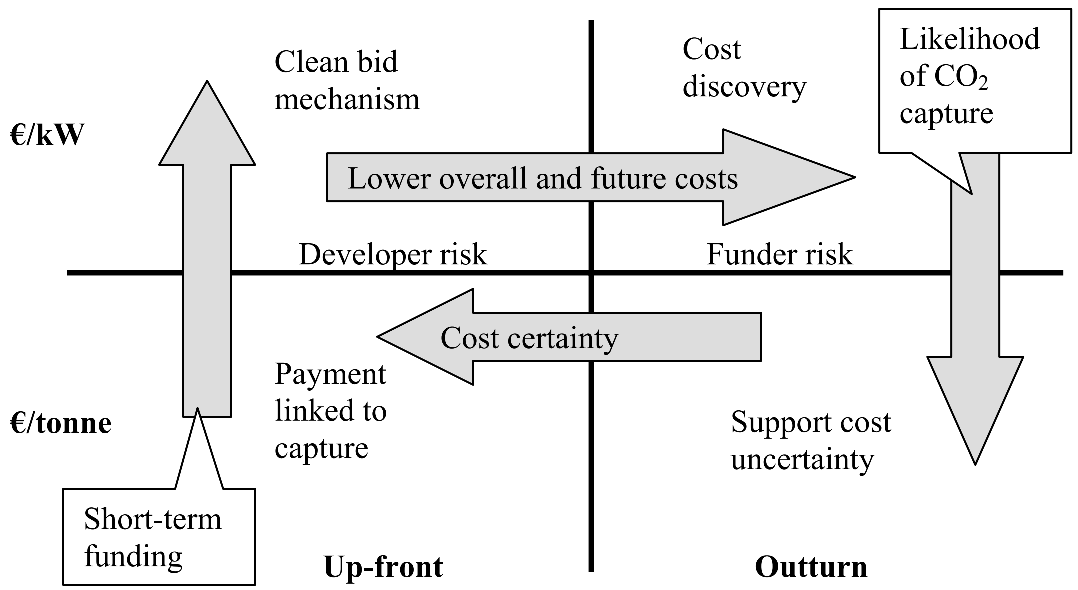

Figure 3.4.1 Diagram of key influences on competition / support type.

Funding Arrangements

The arrangements for funding a support scheme will probably be driven by the source of funding and the political pressures on the relevant funding body. As discussed above, the funding sources all lie within the Member States and so the arrangements discussed below are from a MS perspective.

The most straightforward method, which is particularly suitable for covering additional capital costs, is a form of capital grant, funded by general government funds. The source of funding is the tax-payer from general (blind) taxation. However, this is a straight drain on government funds and hence may be less attractive.

Tax revenues could be hypothecated for climate change purposes and raised as a specific, and possibly additional, "green tax". The same revenues could be derived from the electricity consumer by means of a "green" levy on all electricity sales. This mechanism allows for the possibility of exempting certain categories of consumer (eg very large industry or small and elderly individuals). The method is similar, but the target population is different.

Another mechanism for providing capital subsidy is via a tax-break of some sort; this could be in the form, for example, of a tax-free capital allowance for the first year of a CCS qualifying project. There are a number of precedents for this kind of arrangement and it has the benefit of requiring no cash payment to the developer.

The other source of funding which is widely proposed is by recycling the funds from auctioning of future NAP allowances under the EU ETS. The ownership of the carbon allocations and hence the funds lies with the Member States, so it is more likely this would support a MS initiative rather than an EC-administered arrangement. In effect, the funding is again sourced from the national tax-payer. This kind of arrangement is particularly suited to ongoing support for actual carbon capture and storage costs.

Auctioning of allowances for Phase III onwards has the additional benefit of supporting the carbon price in the EU ETS and hence accelerating the phasing out over time of the need for any public subsidy. As above, the subsidy could be provided to qualifying developers as a capital grant / carbon price support directly, or it could be done indirectly by granting free multiple allocations of allowances to qualifying plant within the auction process. This latter arrangement would appear to have possible political attractions as there is no actual cash generated or transferred to the plant and such free allocations could be administered at an EU level through the NAPs.

The price of carbon is a key issue here and, as mentioned above, the current market level and the confidence of the investor community in it would not support CCS plant. However, the annual volume of carbon from supported power plant would represent a very small fraction of the NAP for any MS. Hence even at recent low carbon prices, the revenues available from auctioning at any plausible forward price level would easily cover the necessary support costs for all envisaged demonstration plant. There would also be little expected disturbance to the ETS carbon price from small percentage additional allocations (effectively market leakage).

4 OUTSTANDING ISSUES

CO_2 Physical Disposal

There remains a fundamental risk associated with all CCS plant which is the necessity to achieve physical storage of the captured CO_2. The successful operation of the carbon capture part of the HYPOGEN plant is entirely dependent upon the storage process

If the physical storage cannot take place for some reason, there will be almost no prospect of storing CO_2 in any other form or location. When compressed to supercritical state, CO_2 is almost incompressible and hence, even with a relatively long pipeline connection, linepack storage is not a realistic possibility. The consequence would be venting of the CO_2, either from the captured gas or, more probably to avoid capture and compression costs, by disabling the AGR mechanism. In the case of natural gas post-combustion capture this would be relatively straightforward. However, in the pre-combustion case, this would have a significant effect on the syngas composition and the downstream power processes. This is an operational risk that should be factored into the design.

The commercial consequences are the costs of failing to capture the CO_2, which could be large if the problem continued. Hence, the type of contractual agreement with the storage operating company (assuming an arms-length arrangement) should have a physical take or pay clause. It is also likely that the physical offtake arrangements would be of a nature whereby the storage operator was obliged to take CO_2 as and when delivered, in order that the CO_2 disposal did not interfere with the optimal scheduling of the plant and its maintenance.

Hydrogen Income Risk

The market for hydrogen from the HYPOGEN plant, especially that for supporting transport developments, is not well developed and hence there is a considerable risk on the expected forward price. This issue was raised and discussed in D6.2.1 and the proposed mitigation was to sell hydrogen only when it achieved a higher price or firmer income stream than using the hydrogen to produce electricity.

This optionality approach leaves the forward electricity price as the parameter which underpins the plant finances; this is well understood by investors and can be covered in a standard way by a Power Purchase Agreement (PPA) or taking merchant risk.

CO_2 Volume Shortfall

Poor (or non-) performance of the plant and / or the CO_2 separation and conditioning equipment could lead to a shortfall in expected CO_2 volumes captured. The technical aspect of this can be covered by technical / performance guarantees, but these will not cover the downstream impacts.

As discussed in 2.4 above, there is a potential impact on the pipeline, with stranded costs not served by the expected throughput. There is also an impact on the storage arrangements where investment will have been made to adapt or create the storage area to be suitable to inject CO_2. This investment would also be left stranded.

5 SUMMARY AND CONCLUSIONS

The analysis and discussion above is quite wide-ranging in the topics it touches on even though it focuses only on the novel risks associated with a HYPOGEN plant. This is an indication of the complexity of some of the issues and the interdependency of many of the potential ways forward.

That said, it is possible to drawn the following important conclusions:

1. The most important factor in tackling the risks of a HYPOGEN plant is continuity and firmness of policy and regulation relation to CCS. This in turn will lead to confidence in the forward market for carbon (and the EU ETS), facilitating private sector investments in the capture and storage process.

2. The least-cost route to the public sector in achieving CCS is through early and firm policy with associated legislation and regulation.

3. The level of public support needed for HYPOGEN is dependent upon the effective alternative reference plant, which in turn is dependent upon type and firmness of the prevailing regulation.

4. If Phase III EU ETS allocations are auctioned, Member States will almost certainly derive sufficient funds from this to provide the level of support needed for a full programme of CCS demonstration plant, including HYPOGEN.

5. The alternative of providing multiple free carbon allowances within the EU ETS to eligible plant would appear to have some attractions as a political mechanism.

6. It would seem most appropriate to support additional capture capital costs by some kind of capital grant / tax relief, but support for the on-going additional operational costs would be more appropriately supported on a carbon-captured basis.

6 REFERENCES

Reference is made in the text above to various reports generated within the DYNAMIS project. They are listed here with their titles and level of dissemination.

1. D2.4.3 "Final report on concept evaluation"; restricted.

2. D6.1.3 "Emissions trade market assessment study for a HYPOGEN plant"; public.

3. D6.2.1 "Identification of Base Conditions for Debt Finance"; public.

4. D6.2.2 "Financing perspective on technology options studied in SP2"; restricted.

5. D6.2.3 "Potential Role of EIB and Public / Private Partnerships"; public.

Appendix 1 Diagram of Power Station Project Risks