Deploying large-scale polygeneration in industry

WP4: Technical, economic and financial appraisal

Blanca Perea

30th October 2008, Brussels.

Once the technical feasibility of a project is proven, why would a polygeneration project be stopped?

increase equipment price

risk

spark spread

client risk

IRR

connection to the grid

return

internalizing CO_2

barriers

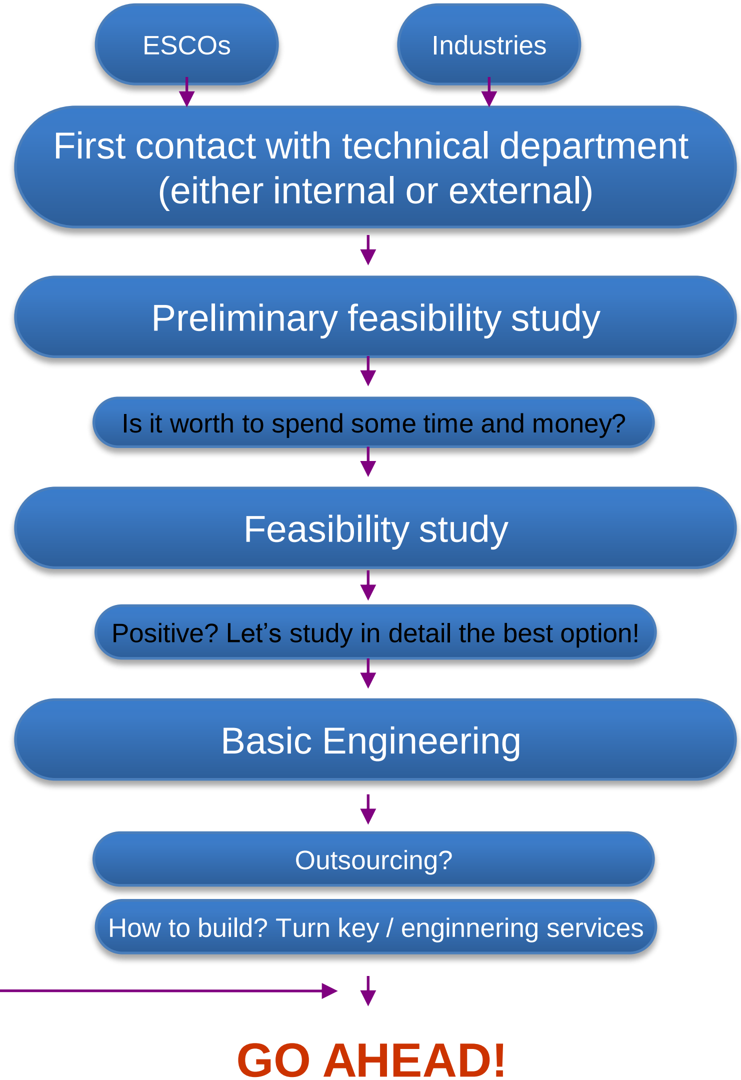
instable legislation

utility attitude

Steps an industrial polygeneration project goes through

- Private developer
- Engineering consultancy
- Comparison with other technologies
- Interconnection feasibility
- Heat load analysis
- Comparison of all suitable technologies
- Estimate rough investment for all options
- Energy Efficiency (PES)
- Economics of the project (without financing)
- Final budget calculation
- Gas + electrical connection conditions
- Construction planning
- Performance

Financial appraisal



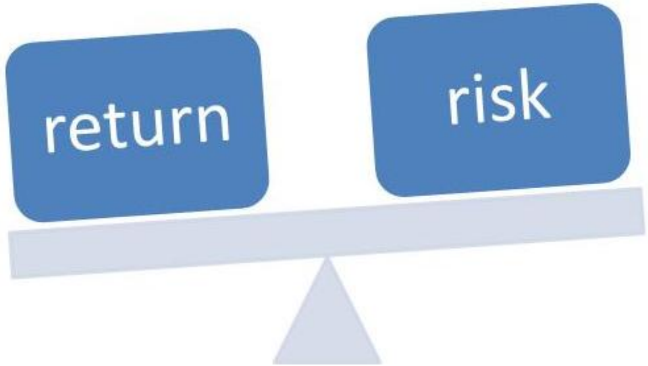
Economic and Financial Appraisal of a polygeneration project

Estimation of the return: Cash flow estimation

- Investment estimation
- Operation

Financial evaluation

- Identification of best practices for ESCOs, Industrials, Utilities, Financing institutions
- Acceptance criteria



Risk analysis and mitigation

- Types of risks attached to a polygeneration project: Legislative risks; Operation risks; Economic risks
- Risk mitigation

D-Ploy questionnaire

The questionnaire

- General information
- Economic appraisal
- Financial appraisal
- Risk assessment

Who answered – patterns

- ESCOs, Industrials, Utilities, NO Financing institutions
- Covered countries: Austria, Belgium, France, Spain, UK
- Power range: 0,5 MW to 500 MW
- Industrial sectors: all (chemical, food, refinery and paper covered)
- Type of cycle: both simple and combined cycle with all kinds of fuels

DIFFICULT TO GATHER DATA

CONFIDENTIA L INFORMATION

Cash flow estimation

Investment

- Estimation of the investment

Operation

- Income: electricity to the grid; electricity to the client; premiums, feed-in tariffs, other complements; Heat to process.
- Expenses: fuel; O&M; back-up electricity; insurance; general expenses

Cash flow

- Steam or/and electricity discount
- Cash flow: income-expenses

Figures of merit

Acceptance criteria

Estimation of the investment-project basis & analytical fits

Project basis:

- Offers will be requested to define a final budget. For feasibility analysis purposes, at least offers for main equipment should be carried out.

Rough estimation for cogeneration (2-30 MW)

- Simple cycle with gas turbine 800 k€/MW
- Simple cycle with engine 700-800 k€/MW
- Combined cycle GT 1000-1100 k€/MW
- Biomass 2000-3000 k€/MW

Rough estimation for trigeneration (2-30 MW)

- Simple cycle with gas turbine 1000 k€/MW
- Simple cycle with engine 900 k€/MW

Estimation of the investment – analytical fits per system

Total Investment in a polygeneration plant

- Cost of main systems
- High voltage system & power converters
- Medium-low voltage system & control
- Fuel system
- Mechanical system
- Civil work
- Provisions and contingencies
- Engineering
- Turnkey management
- Connection to the grid
- Other costs

Main equipment	**Investment (k€/MWe)**
Steam turbine - condensation	I = 538,59 · (E) $^{-0,163}$
Steam turbine - backpressure	I = 466,09 · (E) $^{–0,0659}$
Gas turbine	I = 389,99 · (E) $^{-0,023}$
Engine – natural gas	I = 341,36 · (E) $^{-0,0525}$
Engine – gas oil	I = 396,69 · (E) $^{-0,0097}$
Steam boiler – acuatubulares 2 level P	I = 240,80 · (V) $^{-0,15}$
Steam boiler – acuaotubulares 1 level pressure	I = 143,70 · (V) $^{–0,2132}$
Steam boiler – pirotubular mixtas	I = 258,98 · (V) $^{–0,78}$
Steam boiler – pirotubular convencional	I = 38,13 · (V) $^{–0,2}$
Absorption machine – double effect with steam	I = 197,56 · (F) $^{-0,369}$
Absorption machine – double effect with overheated water	I = 194,48 · (F) $^{–0,7493}$
Absorption machine – double effect with hot water	I = 191,02 · (F) $^{–0,2631}$
Absorption machine – simple effect with steam (NH_3)	I = 684,97 · (F) $^{–0,2188}$
Gas compressor	I = 29,08 · (E) $^{-0,1307}$
Electrical chillers	I = 98,32 · (F) $^{-0,2656}$

Estimation of the investment – analytical fits per system

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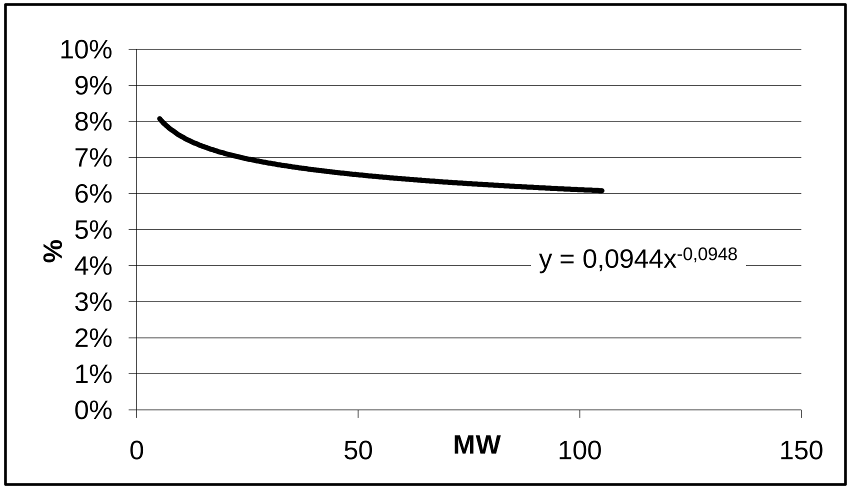
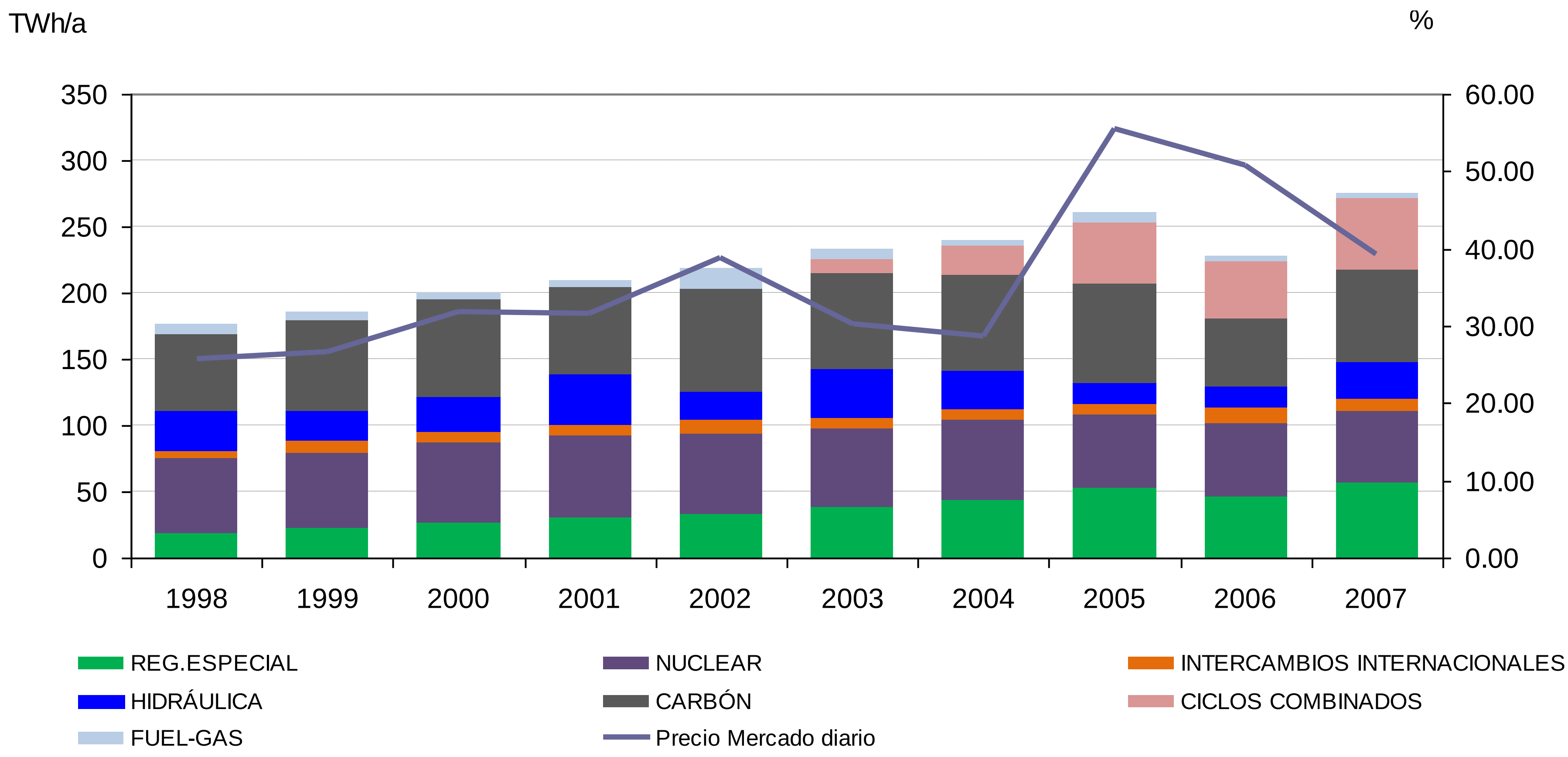
Natural gas engine simple cycle	
High voltage electrical system and transformers	$I/I_{main\ equipment} = 0{,}2605 \cdot (PEP)^{-0{,}3116}$
Medium and Low voltage electrical system and controls	$I/I_{main\ equipment} = 0{,}1932 \cdot (PEP)^{-0{,}608}$
Fuel system	$I/I_{main\ equipment} = 0{,}0428 \cdot (PEP)^{-0{,}2969}$
Mechanical system	$I/I_{main\ equipment} = 0{,}2885 \cdot (PEP)^{-0{,}24295}$
Water treatment system	$I/I_{main\ equipment} = 0{,}0564 \cdot (PEP)^{-0{,}4829}$
Civil work and structure	$I/I_{main\ equipment} = 0{,}2925 \cdot (PEP)^{-0{,}1879}$

CC High Voltage System and Power Converters



Operation – electricity prices [focus on Spain & UK]



Significant participation of Combined Cycle & Low hydraulic participation lead to higher pool prices

Operation – electricity prices [focus on Spain & UK]

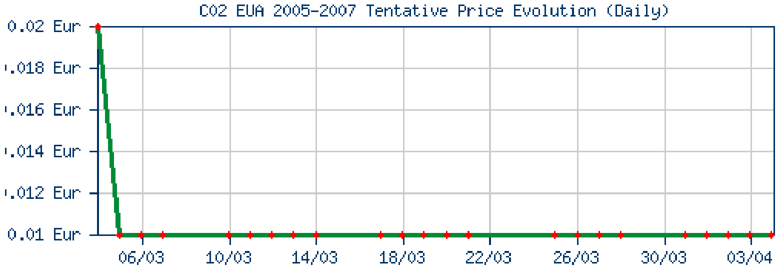
The contribution of combined cycles for electricity production becoming more important in Spain we can assume that most of the time natural gas price will determine the electricity prices.

$$\text{Electricity Prices [PMD]} = \text{Pgas}/\text{Ref}_E + \text{O\&M} + CO_2$$

where:

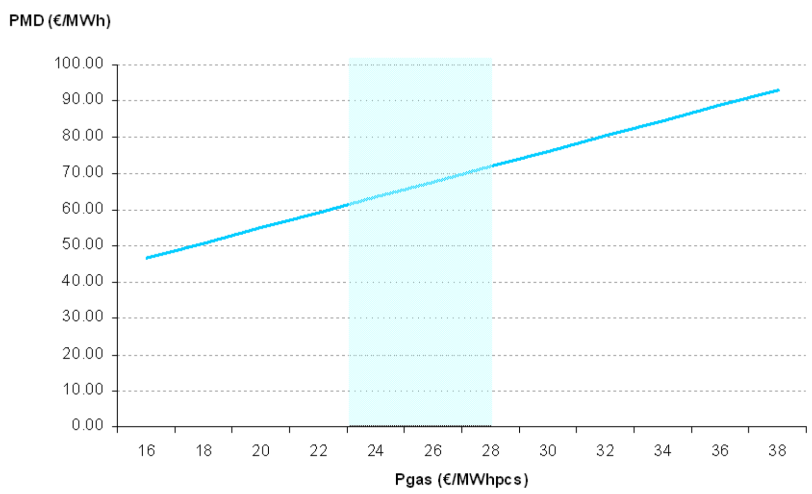
Ref_E: Reference efficiency for a combined cycle [52.5 %]
O&M: Operation cost and maintenance ≈ 5 €/MWh
CO_2: Associated cost: 1 MWhpci = 0.20196 tCO_2
1 MWhe → 1.9 MWhpci → 0.385 tCO_2 ≈ 8 €/MWh

EUA 2007

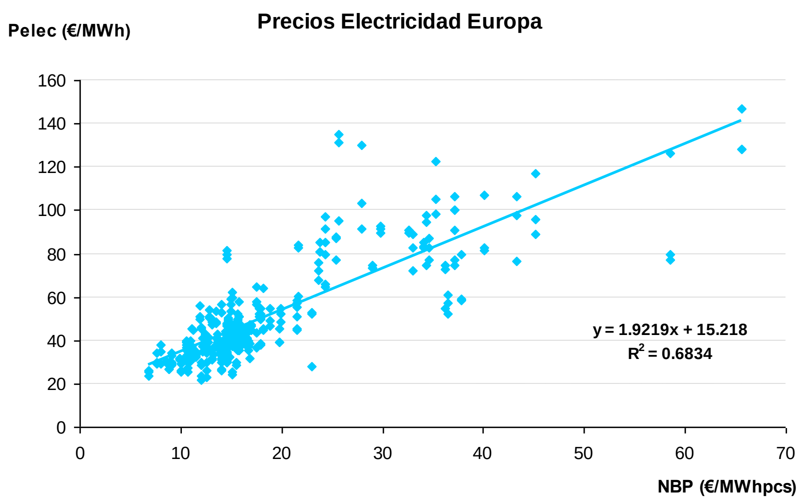


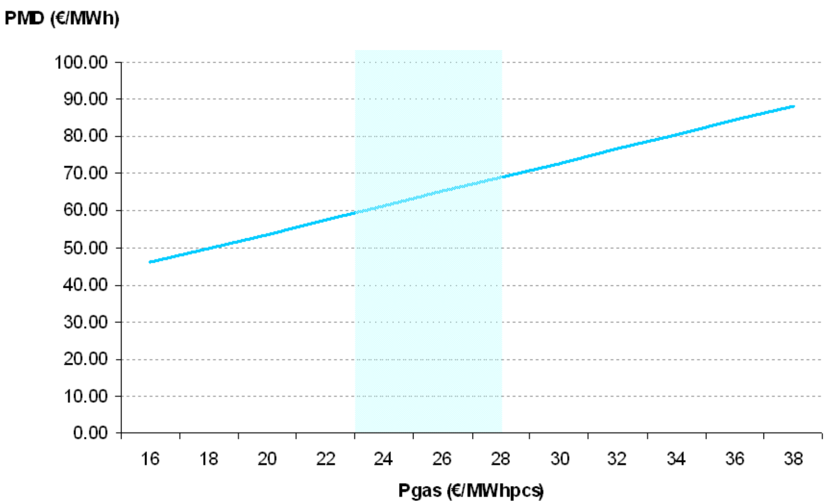
EUA 2008-2012

Operation – electricity prices [focus on Spain & UK]

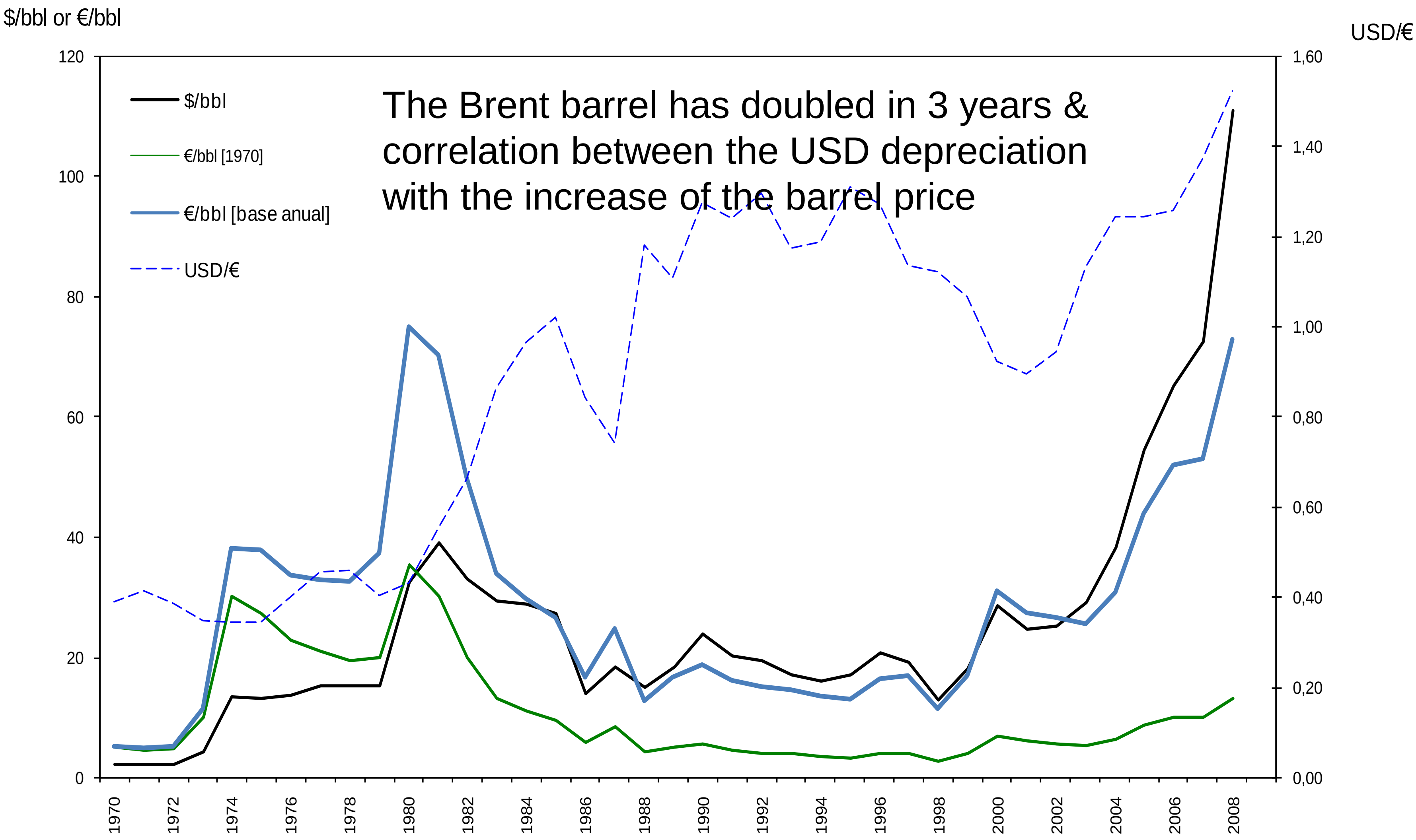


- Natural gas prices between 23-28 €/MWh_{HHV}, the electricity prices should oscillate between 60-70 €/MWh
- If we compare to the electricity and gas prices in European markets, similar results are obtained





Operation – fuel prices volatility



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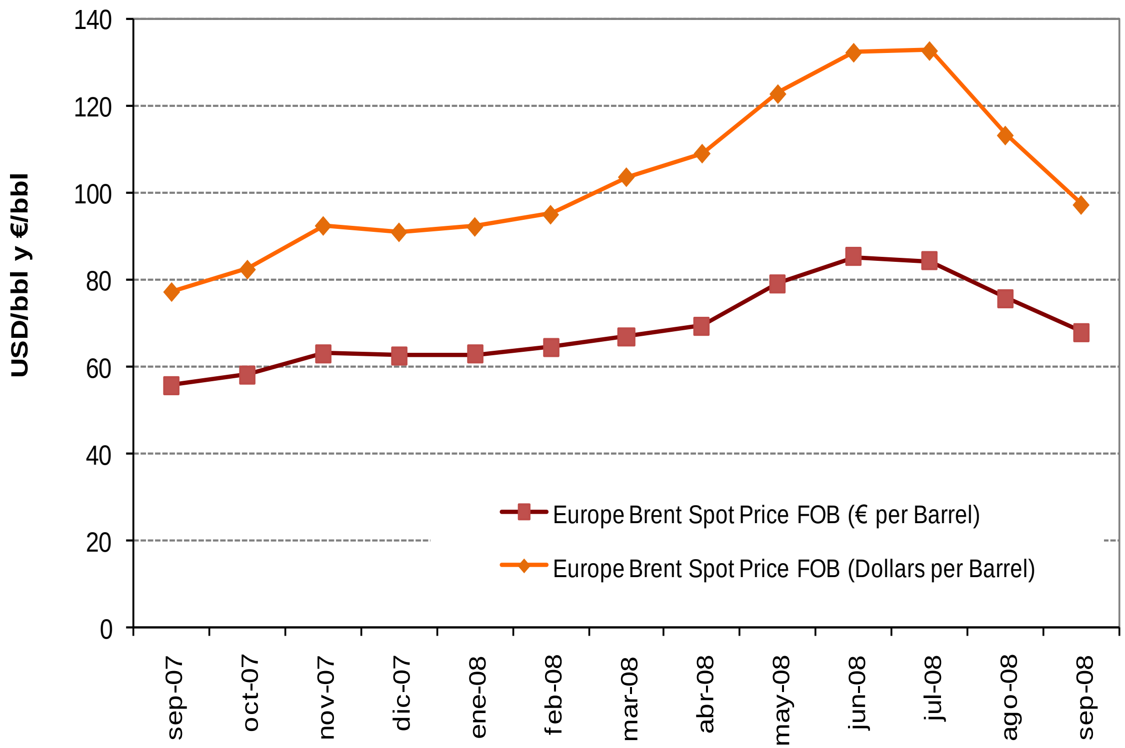


The primary driving force for cogeneration is the economic advantage derived from the efficiency of fuel use in a cogeneration facility as compared to separate electric and steam generation.

Increase in cost of oil (should) drive energy prices up, increasing the value of cogeneration's inherent energy efficiency. Oil crisis lead to a resurgence of interest in cogeneration.

Figures of merit & acceptance criteria

Net Present Value is used by all the questionnaire

- Discounted cash flows generated during the life time of the project or the PPA
- Discount rate: WACC + risk premium

Internal Rate of Return (IRR) after tax

Point out at numbers 9 to 12 %

Payback periods

Should be according to IRRs. Point out 4 to 7 years

Profitability ratio

Only one company was using it

ROCE

Only one company was using it

IRR $>$ WACC + risk premium

$$K_W = \frac{(1-t)\cdot K_D \cdot D + K_E \cdot E}{D+E}$$

7 % $<$ WACC $<$ 9 %

Financial appraisal

Preferred way of financing

- Direct lean
- Project finance ← ESCOs
  Leverage of 70% - 80%
- Capital lease
- Operating lease

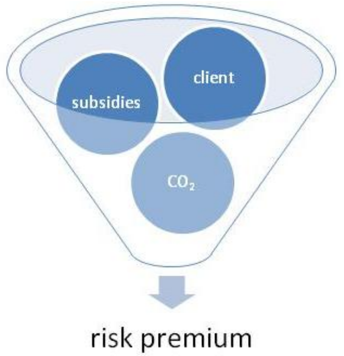
(Capital lease and Operating lease) ← ESCOs in partnership
Industrials

Risk assessment

Legislative risk
- Amendment of a law
- Changes in environmental regulation
- Loss of license

Economic risks
- Increase in capital cost
- Fuel price fluctuations
- Electricity price fluctuations

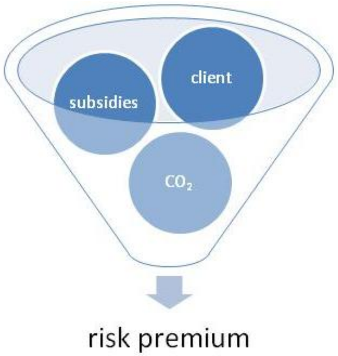
Operational risks
- Reduction in number of working hours
- Heat demand reduction
- Performance degradation
- Fuel shortage
- Major force event



Risk assessment – ranking the most critical aspects

- Client risk
- Legislative changes
- Subsidy risks
- Spark spread risks (power to fuel ratio)
- GHG allocation procedure (CO_2, NO_x)
- Insurance costs
- Labor costs
- Know-how
- Technical risks
- O&M Costs variations
- Currency rates

Pointed out as one of the higher risks. Would lead to lower efficiencies, loss of license.
Could be partially mitigated when establishing the contract.



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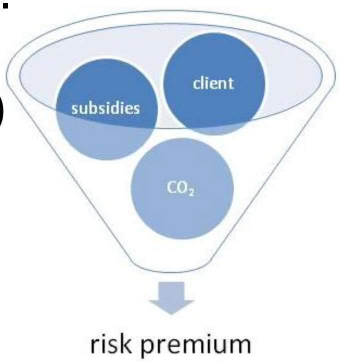
A favorable state regulation and utility attitude in developing cogeneration are extremely desirable: Interconnection problems and electricity dumping from utilities are extremely harmful.

Instability is pointed out as a major problem.

(see Kaj's talk)



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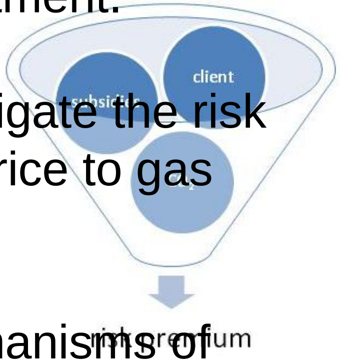
Fuel prices must be sufficiently attractive vis-à-vis electricity prices to make the economics viable. When the electric production is predominantly based on oil and gas, cogeneration opportunities have been attractive due to the relatively high cost of electricity. In market structures based on coal or hydro, the lower prices of electricity make cogeneration an unattractive investment.



Some partners mitigate the risk by indexing heat price to gas price

Actualization mechanisms of feed-in tariffs or premiums

Risk management: fuel prices mitigation

It is difficult for companies to foresee prices and therefore to foresee their results

Organized Market – Stock exchange Standardized in terms of:

- quantities (n. Brent barrels)
- expiring date (12th of each month)
- fluctuations with defined maximums
- financial deposit (need to keep a cash placement)
- credit risk

Out of the stock exchange - over the counter (OTC) Non-organized market:

- the two parties agree prices and expiring dates
- credit risk is assumed by each party
- no need for financial deposit
- contract at a fixed price: it is compulsory to buy/sell at the price that has been agreed
- contract at a maximum price. Price of the product for the future at defined cost: premium
- contract with maximum and minimum price: premium.

Sometimes the risk is assumed by a financial entity

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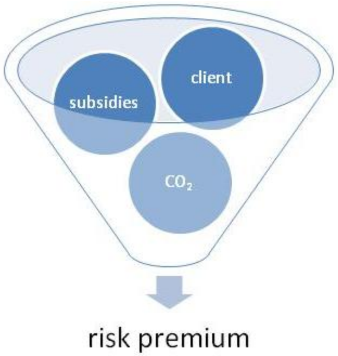
ETS Directive will certainly have an impact on the economics. Partners are beginning to feel that GHG prices will have to be internalized (see Thomas' talk)



Risk assessment – ranking the most critical aspects

Client risk

Legislative changes

Subsidy risks

Spark spread risks (power to fuel ratio)

GHG allocation procedure (CO_2, NO_x)

Insurance costs

Labor costs

Know-how

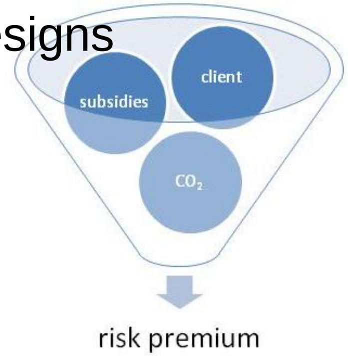
Technical risks

O&M Costs variations

Currency rates

Increased 1999-2000 due to big failures in many CHP plants in Europe, though seems stabilized at the moment.

Conservative approach towards new equipment designs



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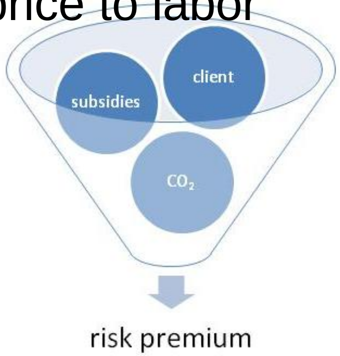
While in some countries the labor costs could be a problem, some partners mitigate this risk by indexing the heat price to labor costs



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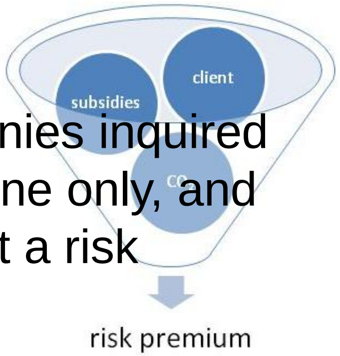
Most of the companies inquired operate in the € zone only, and therefore this is not a risk



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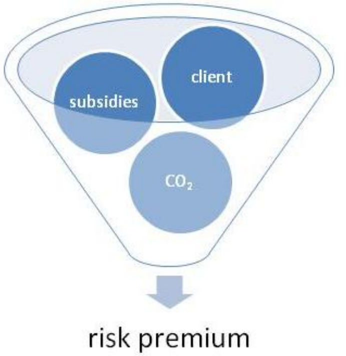
2 % to 3% risk premium



Risk assessment – more comments

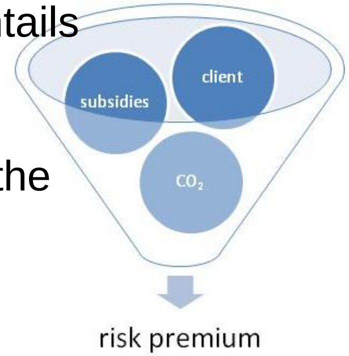
- Supporting schemes in form of feed-in tariffs, premiums, CHP certificates or green certificates are implanted in all the countries and the inquiries reveal that no polygeneration project would be attractive without such subsidy, except for large plants (above 25 MW with a large heat demand and low electricity demand – high efficiency & economies of scale)

- No tax rebate is typically applicable to polygeneration projects

- All the interviewed companies rely on in-house financial experts

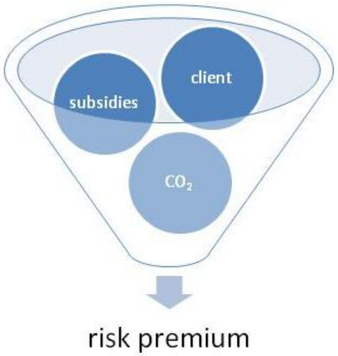
- No common hurdle rate is used across projects, instead risks analysis is performed on a project basis. There are some industrial sectors that appear to be more risky than other sectors since they have historically fluctuations. For instance, the paper sector is extremely risky, while the chemical industry entails some risk and food (basic products, not luxury) is less risky.

- When the sector entails high risk, only the industrial can assume financing the project



Risk assessment – more comments

- Lack of Turnkey offers for large plants
- Engineering know-how or labor costs do not seem to be a problem, except for one country
- Equipment manufacturers are fully booked, which results in main equipment delivery time – in particular for engines
- The increase in prices during 2006-2007 seems stabilized now
- Combined cycle boom does not seem to interfere with smaller size plants
- Type of discount that is offered to the client: ESCOs mainly offer discounts in heat only, though utilities offer discounts in electricity also
- CHP projects need to compete with ‘best alternative’ that sometimes lays within the core business of the industrial



increase equipment price

risk

spark spread

client risk

High PES

resists the test of time and means you are intrinsically hedged against adverse evolution of the energy prices

IRR

connection to the grid

return

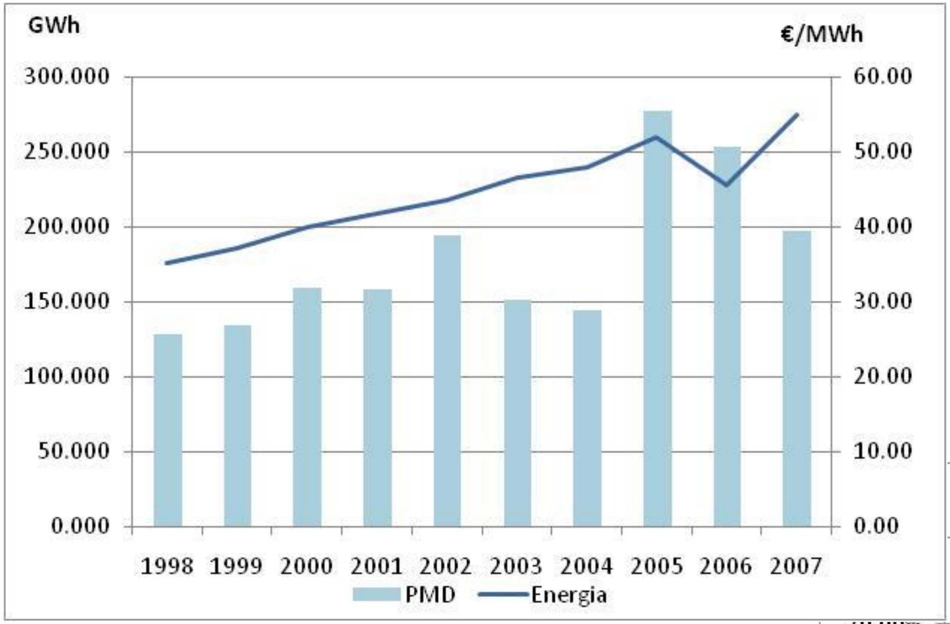
internalizing CO_2

barriers

instable legislation

utility attitude

Operation – electricity prices [focus on Spain & UK]



ELECTRICAL MARKET STRUCTURE determines the prices

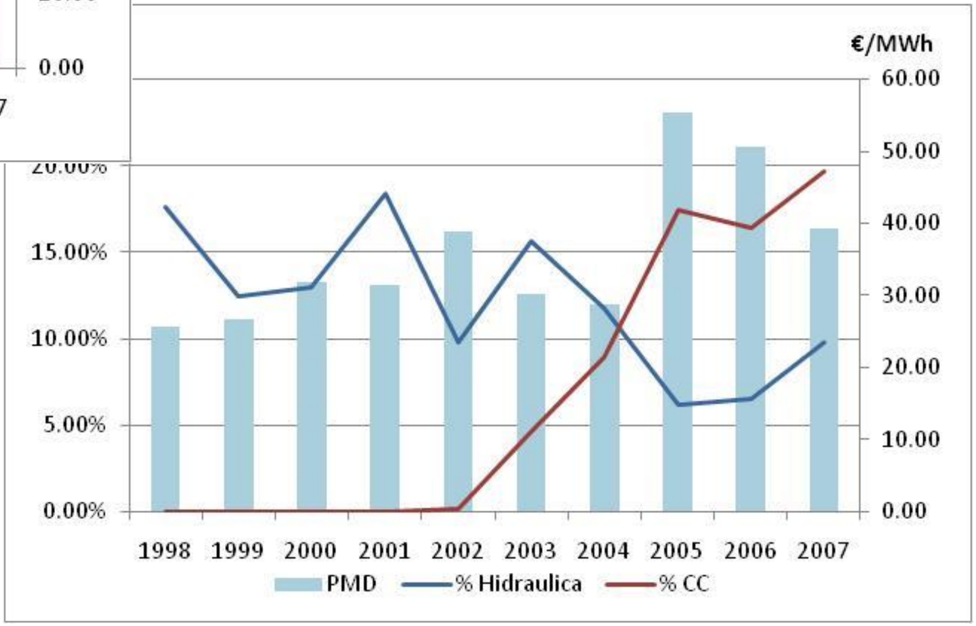
- Period 1998-2004
- Existence of CTC's.

  Average PMD 30 €/MWh

  - 2002 Low participation of hydraulic PMD >40 €/MWh

Period 2005-2007

- Important participation of Combined Cycle.
- Low hydraulic participation
- PMD>50 €/MWh
- 2007 Increase of hydraulic power participation



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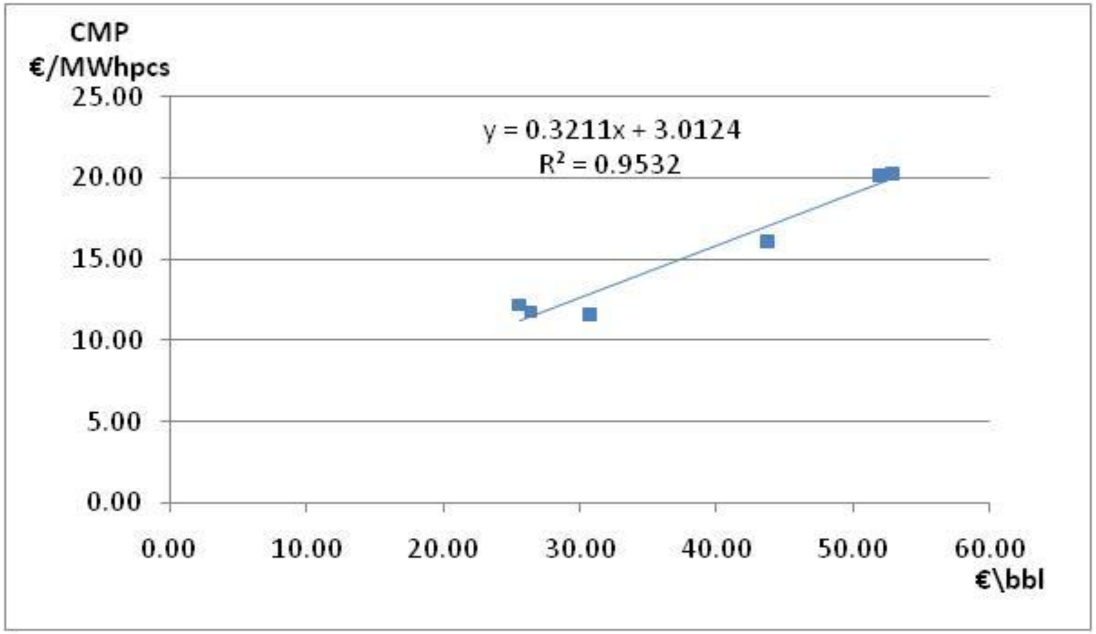

CMP (€/MWh$_{PCS}$)

Brent ($/bbl)	60	70	80	90	100	110	120	130	140	150
1.2 $/€	19.07	21.74	24.42	27.09	29.77	32.45	35.12	37.80	40.47	43.15
1.3 $/€	17.83	20.30	22.77	25.24	27.71	30.18	32.65	35.12	37.59	40.06
1.4 $/€	16.77	19.07	21.36	23.65	25.95	28.24	30.54	32.83	35.12	37.42
1.5 $/€	15.86	18.00	20.14	22.28	24.42	26.56	28.70	30.84	32.98	35.12
1.6 $/€	15.05	17.06	19.07	21.07	23.08	25.09	27.09	29.10	31.11	33.12

- The cost of raw material is a reference price for natural gas, though this is not used in contracts.
- Gas prices paid by CHP plants are indexed to the Brent and €/$ rate (some are referenced to Henry hub, gas in USA, or basket of products derived from oil)
- There is a relation between Brent and the cost of raw material (see graph)
- In order to obtain the final price of gas, tolls for transport and distribution, storage, etc. are to be added Cost aprox. □2.5-3 €/MWh$_{LHV}$

Factors driving market development

Growing demand for power trends to create the need for new generating capacity, a condition more favorable to cogeneration than if utilities foresee excess capacity in the future.