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POWER-GEN EUROPE

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TRACK 1

STRATEGIES FOR THE EUROPEAN POWER INDUSTRY
Three Scenarios for Electricity Production and Demand in 2025

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ABSTRACT
All stakeholders in the power industry are faced with rapid and unprecedented changes and challenges. Monopolies have disappeared, the markets are uncertain and new boundary conditions arise from greenhouse gas emission limitations to fuel-supply uncertainties. Yet, electric energy will increasingly play its role in the economy of the future. According to the IPCC, the energy infrastructure investments will exceed $20 trillion by 2030. Power sector represents $13.6 trillion, of which power generation accounts for half.

To prepare the company for the future, Wärtsilä has carried out research into possible scenarios for the power industry over the next 15 years. Scenarios essential describe alternative futures and how they might come about and are valuable tool for enhancing strategic decision-making. The groundwork consisted of desktop research combined with extensive internal specialists and managers and external interviews with global decision makers and technology experts. Based on this information, a layers structure was created that contains essential issues influencing electricity production and use.

In the end, Wärtsilä found three rather different dominant scenarios, alternative stories about the future, revolving around the issue of power – in terms of energy but also of market structure: Green Earth, Blue Globe and Grey World.

The paper will discuss the methodology used to develop the three scenarios and will describe the major elements of these scenarios. Next to that, it will show indicators along a time line that indicate that a typical scenario is actually happening.

POWER TO SHAPE THE FUTURE
Today, two major challenges top the economic, social and environmental agendas of the world. On the one hand we have to produce enough electricity to improve the living standards of a growing population. On the other hand we must curb climate change. The power sector has a key role to play in this while facing the additional challenge of limited fossil fuel reserves.

According to the Intergovernmental Panel on Climate Change, the energy infrastructure investment needed by 2030 exceeds $20 trillion. According to estimations from the International Energy Agency, investments will exceed $26.3 trillion.

Of this amount, the power sector represents $13.6 trillion, of which power generation accounts for half, with transmission and distribution making up the remainder.

These issues are more than relevant for Wärtsilä. As a provider of complete lifecycle power solutions for our customers we need to make the right decisions regarding long-term product development in order to be the preferred partner for future investment. At the same time we must do our share when it comes to solving climate and energy challenges.

One method of making sense of a complex and changing environment is creating scenarios. Scenarios essentially describe alternative futures and how they might come about.

Our experience at Wärtsilä suggests that our scenarios enhance our strategic decision-making by challenging conventional modes of thinking. The very nature of a scenario is that of a multi-dimensional discussion. Governments, companies and individual citizens all have the power to make choices that affect our common future.
A STEP INTO THE UNKNOWN
Energy markets are now in uncharted territory. Never before have there been as many fundamental changes and challenges at the same time. The main concern that requires immediate action is the growth of carbon dioxide (CO₂) emissions.

Scientists and engineers must develop completely new, visionary technologies and not just fine-tune existing solutions. In order to be successful in these turbulent times, we must think about what the future might look like.

GATHERING EXPERTISE FROM VARIOUS SPHERES
In 2008, Wärtsilä’s international and cross-functional team spent over 8000 hours analyzing the question of electricity production and use in 2025. The idea was to understand our clients’ future needs in greater detail. In order to have as broad a perspective as possible, the team turned to various experts, including academics, nongovernmental organizations (NGOs), business leaders, government representatives and others, to discuss issues such as macroeconomics, geopolitics and the environment.

THE FRAMEWORK
To make sense of the complex contextual issues, we created a structure consisting of eight layers (Figure 1). The layers are essentially topics that broadly influence electricity production and use, from climate change and geopolitics to public opinion and technological development.

CLICK TO VIEW FIGURE 1:
THE MODEL

After researching these thoroughly and discussing them with experts, we defined which developments and influences we could be certain of – and which we could not. In the end we were sure of only two things: that oil production is peaking and that the share of renewables will increase. By analyzing key uncertainties, we found three different scenarios, revolving around the issue of power, not only in terms of energy but also influence. Who has it and why?

What is its impact?

SCENARIOS ARE NOT FORECASTS
The essential difference between forecasting and scenario-thinking is that forecasts are based on extrapolation from a past trend-line that leads to a future value – such as that of the price of oil – and assumes nothing changes. This future picture is precise but may be misleading. In scenario-thinking, understanding the behaviour of the players as a system allows us to observe several plausible future outcomes, including discontinuities. This future picture may not be precise but it may prove more useful in that it could be more reliable or accurate.

Essential scenario usefulness is given by the capability to reply not to the question “Will it happen?” but to “What would we do if it did happen?”

CLICK TO VIEW FIGURE 2:
SCENARIO ZONE (COURTESY OF NORMANN/PARTNERS)

The key rationale for the power scenarios is that there are very few things we can be certain of when we look into the future. We felt that one certainty is that oil production has reached its peak. We also believe that the share of renewables in electricity production will grow. However, we cannot be certain about which the key renewables will be.

We identified three alternative futures. They are based on a process of identification and iteration of the uncertainties that arose from the eight-layer frameworks and the application of our understanding of how the system diagrams could work differently.

CLICK TO VIEW FIGURE 3:
UNCERTAINTIES

THREE SCENARIOS
Wärtsilä found three dominant scenarios, each an alternative story about the future and revolving around the issue of power in terms of energy and market structure: a Green Earth, a Blue Globe and a Grey World. We now briefly summarize these.

The Green Earth scenario is shaped by individual citizens, consumers and voters. Natural disasters associated with climate change have shown us that we, the consumers, must do something about the changing climate. Using natural gas as a transition fuel, we have focused on renewables such as wind and solar power.

The world economy grows at a modest sustainable pace and the geopolitical situation is stable. We accept the scarcity of resources and live, not unwillingly, in a sustainable way.

The key variables in this scenario are: that individual consumers and citizens have power; accepted scarcity; a focus on renewables; and sustainable living.

The Blue Globe is a market-oriented, prosperous world. Utilities power our way of living. Their focus is on large-scale coal and nuclear plants. Policy is driven by two key factors: the need for economic growth and the curbing of emissions.

Carbon capture and storage (CCS) has become the key solution, allowing us to keep using coal in existing and new plants. Transportation has been electrified and thus transport has less impact on the environment. The subsequent reduction in oil demand has led to a restructuring in geopolitical networks.

The key variables are: utilities have power; energy is in abundance; a focus on coal; and the electrification of our ways of living.
CHANGE HAPPENS.
THE ENERGY BUSINESS NEEDS FLEXIBILITY.

Environmental rules tighten, short-term energy demand fluctuates and long-term demand grows. Fuel prices and availability, weather conditions and technology – the only constant is change. How can energy be produced in a way that’s both environmentally and economically sound?

Our answer: add flexibility to the energy mix. Read more about flexible power generation at www.wartsila.com.
The Grey World is ruled by governments. Scarcity of resources and energy security are major issues. Governments try to make scarce supplies last, leading to considerable changes in society. Political tensions run high because of the uneven geographical distribution of energy resources. Natural gas is the most important energy source, and climate change has virtually dropped off the political agenda.

The key variables are: governments have power; there is friction because of scarcity; a focus on indigenous sources; and living is on the edge. The three power scenarios are different and three main themes are apparent. Let us now analyze in more detail what that different scenarios look like and how they could unfold in time, and look at the cause-and-effect loops.

**GREEN EARTH**

Green Earth is a scenario in which the idea of sustainability is conquering the world from the ground up. It is being driven by individual consumers and voters. In the West, people have become more aware of the fact that climate change is real and that it has become a problem, along with the overuse of natural resources. Consumers have therefore taken it upon themselves — with the help of governments — to change the way they live and consume. In turn, developing countries are following suit. We, the consumers, demand sustainable products and thus drive innovation. Parties and politicians with green platforms and values are garnering increasing support from the populace.

Where politicians fail to embrace sustainable values, it only serves to accelerate the grassroots movement because such politicians are seen as unable to provide the solutions required to make sustainability a priority. Meanwhile countries with sustainable policies already in place are advancing their efforts, thus presenting an example for advocates of sustainability around the world, as well as supporting the continued expansion of the renewable energy industry.

Finally, even though climate change as a phenomenon remains under debate, people still see sustainability as something valuable in its own right — something worth striving for.

The West sets stringent environmental standards for the lifecycles of products and services. Countries reluctant to produce environmentally sound products lose competitiveness. Cheap labour is no longer in fashion — energy efficiency is.

Mass transportation and electric vehicles are the preferred modes of transport. This reduces demand for oil. An ethos in favour of innovation means both energy production from renewable sources and energy efficiency develop rapidly. Natural gas has become the only acceptable energy source, and climate change has virtually dropped off the political agenda.

The key variables are: governments have power; there is friction because of scarcity; a focus on indigenous sources; and living is on the edge. The three power scenarios are different and three main themes are apparent. Let us now analyze in more detail what that different scenarios look like and how they could unfold in time, and look at the cause-and-effect loops.
the environment. The consequent reduction in oil demand has led to
an increase in the use of coal. Thanks to CCS, we keep using coal,
along with other centralized solutions, such as nuclear power and
large-scale wind parks, to tackle both economic and environmental
issues.

Transportation has been electrified and thus it has less impact on
the environment. The consequent reduction in oil demand has led to
a restructuring of geopolitical networks. Several, linked carbon emissions trading
schemes exist in the West.

China and India will introduce and implement major energy
savings and efficiency improvement programmes. China, where a
lot of new manufacturing capacity and infrastructure is being built,
is one of the front runners, together with the countries of the West, in
developing and deploying energy-efficient technologies.

CLICK TO VIEW FIGURE 5:
GREEN EARTH CAUSES AND EFFECTS

BLUE GLOBE
The Blue Globe is a market-oriented, prosperous world powered by
clean coal and nuclear power.

The global recession of 2008–2011 and the increasing number
of environmental disasters have given rise to a two-point political
agenda: the need for economic growth and the need to curb
emissions. CCS is seen as the solution.

The lacklustre Copenhagen meeting in 2009 left the climate
question wide open. Meanwhile CO₂ prices in the EU are
predictably high carbon prices, thus making CCS and nuclear, as
dependent on gas.

renewables are not sufficient everywhere, many economies are still
and energy security is a major issue for governments around the
world. Governments promote energy efficiency and demand-side
energy efficiency, DSM and renewable energy. This
grid technology have made it possible for all countries to become
energy-efficient, DSM and renewables, economical. The policy is
based on a four-point action programme:

- Clear caps on greenhouse gas emissions with flexibility on
  how to reach them;
- Active development of carbon trading markets;
- In the case of coal based power generation, only CCS-ready,
  ultrasupercritical plants are allowed to be built;
- A cross-border task force to speed up the commercialization of
  CCS.

The need for cheap energy in the global recession leads to an
increase in the use of coal. Thanks to CCS, we keep using coal,
along with other centralized solutions, such as nuclear power and
large-scale wind parks, to tackle both economic and environmental
issues.

Due to the dominance of coal, CCS has great potential to curb
CO₂ emissions. This, together with nuclear power, energy efficiency,
demand-side management (DSM) and renewables, powers the
world while keeping emissions within acceptable limits.

CLICK TO VIEW FIGURE 6:
BLUE GLOBE TIMELINE

TIMELINE
During the recession of 2008–2012 governments boosted
economic growth, sacrificing short-term environmental concerns in
order to get overall investment back to a high level.

An essential ingredient was to agree on emissions targets and the
costs for CO₂ and methane emissions, enabling utilities to make
proper investment plans. Emission policies are made to fit both
emission targets and economic development.

Emission trading markets are established and prices have been
stabilized. Keeping carbon prices at levels that allow CO₂-free
power generation investment leads to the commercial viability of the
whole value chain of CCS: capture, pumping and storage.

With successful CCS demonstration plants and high investment in
carbon-free nuclear generation, the industry is relieved of the mounting pressure to
curb emissions.

At the same time technological advances in, for example, smart
grid technology have made it possible for all countries to become
habituated to energy efficiency, DSM and renewable energy. This
double-edged advantage electrifies the world while keeping CO₂
emissions within acceptable limits.

The advances in battery technology, hybrid cars and the large
utilities’ strong lead in developing the charging infrastructure enable
a large-scale electrification of most transportation solutions. As
electrification of both transportation and society as a whole is
developing, the world is less and less dependent on oil and gas.

The world demand for oil is still mainly satisfied by the Middle
East. As not all countries have access to coal, and conditions for
renewables are not sufficient everywhere, many economies are still
dependent on gas.

Therefore the role of gas, especially liquefied natural gas (LNG), is
still important. The world is prospering, economic growth resembles
what is was at the beginning of the 21st century.

CLICK TO VIEW FIGURE 7:
BLUE GLOBE CAUSES AND EFFECTS

GREY WORLD
The Grey World represents a bleak future. Resources are scarce and
energy security is a major issue for governments around the
world. Governments promote energy efficiency and demand-side
control to make the scarce supplies last, leading to considerable changes in society.

Carbon dioxide storage does not turn out to be a viable option. The nuclear renaissance ends before it starts because of unexpected problems in old plants which lifecycles have been extended to cater for electricity demand. In most countries, despite government support, public opinion turns against nuclear power and its development effectively ceases. Energy production is based on fuels that are either available locally or guaranteed by means of bilateral agreements.

Natural gas is the most important energy source, increasing the political power of gas exporting countries and their cartel, the Organization of Gas Exporting Countries (OGEC). Political tensions run high because of the uneven geographical distribution of energy resources.

China and Russia compete for power in Central Asia, and military conflicts over energy issues are not uncommon. Countries undermine their potential for economic growth by bidding against each other for LNG.

Climate change has virtually dropped off the political agenda. Renewables such as biofuels are seen as a second-best option for developed countries that lack energy resources. Developing countries are unable to afford renewables and rely on coal, although public opinion is against it.

**CLICK TO VIEW FIGURE 8: GREY WORLD TIMELINE**

**TIMELINE**

There is no global agreement on greenhouse gas emissions. Developing countries continue to put economic growth before emissions targets. And even though developed nations agreed to cut their emissions, many countries soon announced their inability to keep up with the deadlines in the face of deepening economic difficulties.

With energy security dominating the political agenda, climate change is little more than a side note in government policy. The process towards more liberalized energy markets has been reversed.

Concerns over energy security and the inability of utilities to cope with price volatility and an increasingly turbulent market led many governments to take over their largest utilities under the pretence of national security.

Due to an accident, only a handful of new nuclear power plants have been commissioned in the last five years. The failure of CCS has rendered coal politically impractical in most Western countries. In the face of increasing fears over energy supplies, countries have three options. Some countries aggressively promote a combination of indigenous fuels, renewables, efficiency and demand-side control as a means of achieving energy independence, possibly sacrificing economic growth in the process. Others obtain security of supply by forging new alliances with energy-rich nations, leading to a world in which international bodies are replaced by bilateral agreements and small blocks of countries with interconnected interests. Finally, nations with sufficient political and military resources leverage these in an attempt to secure their interests, by force if need be.

Temperatures run high as countries vie for control over crucial resources. Russia and China have been trying to project their power in the region. The Middle Eastern region continue to be a hotbed of radical religious movements and behind-the-scenes intrigue. The forming of OGEC has not made its member states any more internally stable.

The economic growth of energy importing countries is severely undermined by price volatility. Similarly the countries that opted for energy independence via a combination of indigenous fuels and lower consumption are finding it hard to spur economic growth with a cap on energy consumption. The only countries experiencing notable economic growth are those with considerable reserves of fossil fuels and a handful of nations that, due to an abundance of sun or wind or both, are able to satisfy most of their demands with cost-effective renewables.

Coal is still a major part of the global energy mix. With energy security high on the political agenda, even the failure of CCS is not enough to make coal rich countries stop exploiting their reserves. Many developing countries, on the other hand, have no choice but to continue burning coal as other forms of energy would be too expensive. Unable to secure their supplies of natural gas, and with public opinion heavily against non-CCS coal, most fuel-poor developed nations have invested heavily in renewables. In a race to wean themselves off their dependence on energy imports, governments have channelled the vast majority of their resources into established forms of renewable energy: hydro, wind and solar. As a result, even solar is now a mature technology capable of providing sustainable, albeit intermittent, electricity at a moderate cost.

**CLICK TO VIEW FIGURE 9: GREY WORLD CAUSES AND EFFECTS**

**UNFOLDING SCENARIO**

The scenarios help us understand how the markets work and how the future might unfold. The scenarios help us integrate long-term planning into our strategic work and to develop our solutions to meet the future needs of our customers. Based on the scenarios we have developed a tracking framework for analyzing the unfolding of the scenarios.

Analyze of critical themes and uncertainties have found their present.
The tracking of the scenarios will enable us to receive constant feedback about changes in the environment. Moreover the tracking aims to recognize when the natural life of the scenarios has come to an end and when it is time to restart the exercise.

Tracking of the unfolding signals has given preliminary indications that we can now summarize.

1. ECONOMIC GROWTH

The main indicators have recently gone in opposite directions. Stock markets boom on the back of good economic news, indicating that recovery is robust. Central banks keep interest rates close to zero, thereby sending prices rising and indicating bad economic news.

A modest economic growth is forecast for 2010 and onwards. It is questionable whether governments in the West will have the funds to finance the growth.

Emerging market economies, with China in the lead, seem to be more robust. The result: modest or no growth.

2. CLIMATE POLICY

The Copenhagen meeting last year left the climate question wide open and political agreement has left out several items for further discussion in 2010. But even in the absence of a global climate deal, groups of countries continue to uphold their green policies, thereby supporting the expansion of the renewable energy industries.

The result: weak and differentiate.

3. GEOPOLITICAL SITUATION

Global weapons spending hits record levels and countries are still fighting over access to natural resources. China’s non-interference policy seems to have come to its end and the relationship with the US has deteriorated.

Several bilateral, energy-related agreements have been signed. Iran and China cooperate on South Pars, the Iran-Pakistan pipeline that will be operational by 2014, Nabucco versus South Stream. Gazprom aims to be the biggest LNG market player. New shale gas finds may dramatically improve the energy security of several nations, in addition to the US. The result: stable.

4. CHANGE IN LIFESTYLE AND VALUES

Coal plants and CCS initiatives are meeting heavy opposition on a larger scale. Smart grids are being discussed extensively but the investments have not yet started.

Transmission lines is being promoted as the solution to accommodate more intermittent renewables but the investments have not yet started on a large scale. Smart grids are being discussed extensively but implementation will remain a challenge.

5. TECHNOLOGY INNOVATION AND FOCUS

New third-generation renewable technologies are being introduced. In 2008, both the US and Europe invested more generation based on renewables than on fossil fuels. However, new investment in renewables is expected to decline in 2009. Investment in new transmission lines is being promoted as the solution to accommodate more intermittent renewables but the investments have not yet started on a large scale. Smart grids are being discussed extensively but implementation will remain a challenge.

Coal is seen as a dirty and polluting method for producing power, it is very difficult to get any new coal fired power plants permitted in the countries of the West. CCS is the only technology option currently available that could allow abundant, flexible and entrenched fossil fuels to continue to be used for electricity generation without adding to the damaging effects of climate change. The investment and hope are there but public opinion starts to have an impact on the development of the technology. The lack of a regulatory framework stands in the way of CCS’s widespread deployment and it is unlikely that CCS will make a credible contribution without strong legislative and regulatory change. The result: differentiate.

6. ROLE OF GOVERNMENT

Economic recovery needs energy and money. Energy is capital intense, and public funding is needed. Governments have the licence to print money and govern monetary policy. Interest rates stay low but banks are under heavy scrutiny by governments, so they take on the role of regulating real recovery through prudent risk management. Thus, directly or indirectly, there is no disputing that the role of government in the coming decade will be very prominent. Nationalization, subsidies, new legislation on top of protectionism are further signs of the new and different roles of governments. The result: change.

ONE WORLD?

Applying the gate process to the above signals that our future could look like Grey World but on the other hand the above signals reflect a variegated scenario in which all the actors can still play their role.

It is our task to proceed to track the unfolding of the scenarios, to be prepared for various outcomes and to be ready soon to write the history of the future.
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Utility-scale PV and CSP Solar Power Plants – Performance, Impact on Land and Interaction with the Grid

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ABSTRACT
Photovoltaic (PV) and concentrated solar power (CSP) plants form one of the most quickly growing segments of the renewable energy market. Both types of solar plant, boosted by favourable feed-in tariffs, are under construction in different countries. They cover sizes up to the 100 MW, which is commonly the reserve of conventional plants, such as thermal or combined cycle types.

This paper analyzes PV and CSP plant technologies and looks at their impact on the landscape, performance and impact on the grid (in normal and transient conditions). This paper investigates whether they can provide the ancillary services the grid requires to ensure high service continuity and high quality. This paper also discusses possible future scenarios, starting with the requirements of grid codes.

1. INTRODUCTION
Utility-scale PV plants and CSP plants are becoming a reality. The uptake of such plants is expected to accelerate over the next decade, especially in regions such as southern Europe due to the high solar irradiance there and continuous pressure for the implementation of numerous renewable energy generation technologies.

The growth of such plants will only be certain if unlimited access to the high-voltage (HV) and extra high-voltage (EHV) grids is allowed. Besides this issue, the higher penetration of renewable energies, especially wind and solar, brings with it the risk of grid instability when such generating plants are not able to support the grid properly.

This is why the search is on for new developments in the design of devices capable of supporting grid operation and stability. New interconnection requirements, especially those related to utility-scale PV plants, are coming into force in several European countries. Their aim is to form a planning document and decision guidance for project designers and PV equipment manufacturers.

In the light of the above, a qualitative comparison has been carried out between a utility-scale PV plant and a CSP plant with a nominal capacity of around 50 MW. It is a reasonable assumption that this is a reference size for both technologies because it seems a typical capacity for most of the existing plants of both technologies.

It has been necessary to define a specific region – southern Italy – for which the solar beam, or irradiance level, and average ambient conditions are known because these have a huge influence on plant design.

An analysis has been made of the pros and cons of PV and CSP plants in terms of efficiency, energy production and impact on land, in other words how many hectares they cover and what the impact is of this in the regions where installation of such plants seem to be most likely.

This paper also outlines which one of these types of solar plant may today be considered as having the lesser impact on the grid and whether they will contribute to grid stability during transients. It also covers the technological improvements that may be needed to make them comply with the mandatory requirements of grid codes. The analysis does not refer to a specific grid connection point but refers to the European HV network because the majority of the existing utility-scale PV plants and CSP plants are in Europe.

This study refers to European grid and transmission codes, and in particular makes reference to the German transmission code [1], which was the first of any of the European countries to approach the topic of renewable generating units and their impact on the grid.
2. GROWTH IN SOLAR ENERGY RESOURCES AND GLOBAL INSTALLED POWER

2.1 PV INSTALLATIONS OVERVIEW [1][2]
The solar PV sector has been booming over the last decade and is forecast to continue doing so. By the end of 2009 global worldwide cumulative capacity was approaching 1.5 GW. Today Europe is leading the way with more than 1.4 GW, representing over 65 per cent of global cumulative PV installed capacity, and equal to almost seven times the installed power in Japan and ten times that of the US, confirming Europe as a geographical leader in the area of PV installations.

The growth in installations in Europe is even more interesting when compared with the rest of the world, because in terms of market dynamics there has been a significant increase in the number of so-called utility-scale PV plants. However, this lead is the result of strong inhomogeneity in growth in the US and comes from having a confirmed excellent market for PV. Other countries are marking time and yet others seem to be well placed to play an important role in the near future.

These differences can be explained by the relative importance of plant segments – in other words, building installations, industrial installations and multi-megawatt installations – and by the policies of national governments. The result is that rules and incentives exist to promote one segment more than another. Also the morphology of one national territory might be a limitation for some plants, especially large ones.

2.2 OVERVIEW OF CSP INSTALLATIONS [3][4][5]
After almost 20 years of silence, the early years of the Millennium saw interest in CSP rise again. New plants have been built not only in the US but also in Europe.

At the moment the total worldwide installed power is approximately 655 MW, producing 1400 GWh of electricity per year. Apart from US and Spain, other countries where CSP plants being built, or at least are planned, are Australia, India, nations in Central Asia, Mexico and Mediterranean countries such as Italy, France, Greece, Turkey, Morocco, Libya, Algeria, Egypt and Israel.

In contrast to the PV sector, the CSP industry is far less fragmented. Spain has some of Europe’s best solar resources and a favourable tariff regime. The solar CSP sector there is well positioned with 22 projects under construction, totalling 1037 MW, out of the 1.5 GW or so planned globally until 2014.

Italy is the first country to follow Spain in making a significant move in support of CSP projects with feed-in tariffs (FiTs). In 2008, the Italian government issued the legislative decree that set a new FIT for CSP. This decree requires that all CSP plants, including hybrid plants, have to include thermal storage. In Spain, storage technology is allowed but not required for system approval.

3. SOLAR POWER PLANT TECHNOLOGIES

3.1 UTILITY-SCALE PV PLANT

The utility-scale PV plant, sometimes called the central station PV, acts more like a ‘concentrated’ power plant, producing energy and delivering it to the grid. Traditionally, utility-scale PV plants have used flat PV module technology of either crystalline silicon (mono or polycrystalline silicon types) or thin-film (mainly of cadmium telluride – the CdTe type).

Such PV modules range in size from 0.7 m² to 1.7 m² and in peak power from 70 Wp to 250 Wp. The efficiency of thin-film PV modules is typically 10–12 per cent, whereas that of crystalline silicon PV modules is 11–16 per cent.

Another PV technology is concentrating photovoltaic (CPV) plant technology, which is based on the reflection of concentrated sunlight onto highly efficient PV cells, such as copper indium gallium diselenide – or CIGS – and thin-film amorphous silicon.

Nowadays such technology is used only in small or prototype PV installations and therefore cannot yet be considered as a viable alternative to other technologies for utility-scale PV plant installations.

Since the utility-scale PV concept is still new, no clear winner has yet emerged among these different technologies, even though most of the biggest utility-scale PV plants – those with output of 40–60 MW – have been realized by fixed systems.

Tracking PV systems cost more than fixed systems but their performance is better. PV modules are either installed on fixed metallic support structures arranged in long rows, adequately spaced, facing south – in the northern hemisphere – with an appropriate tilt, or they are deployed on tracking devices to follow the sun. PV modules are electrically connected together in series and parallel, and then connected by DC cabling to the centralized inverters, which convert DC power into AC power. The inverters are connected together on the AC side to the plant medium-voltage network, which delivers the energy to the HV or EHV grid by means of one or more step-up transformers.

3.2 CSP PLANT

All CSP plants produce heat or electricity using hundreds of mirrors to concentrate the sun’s rays to produce a high temperature typically between 400 °C and 1000 °C.

The four main CSP technologies depend on whether the solar radiation is concentrated on a linear collector system, as in the case of the parabolic trough and linear Fresnel, or on a central focal point, as in the solar tower and parabolic dish.

Among the possible CSP technologies the parabolic trough seems to be the most commercially proven and it appears to be the one favoured by CSP plant developers. Although the ‘power tower’ lacks experience, with few plants in operation, in the medium-long term this configuration may produce electricity at a lower cost than parabolic trough plants.
On the other hand, parabolic dish and linear Fresnell systems have not progressed beyond their initial demonstration phase, although these technologies have the potential to produce energy with lower capital cost compared with the other two.

The CSP technology taken as reference for this study is based on parabolic trough technology. The main parts of this are the solar field, the heat storage system and the power block.

The solar field comprises solar collectors that collect and concentrate the solar radiation, and solar receivers that absorb the concentrated solar energy and convert it to useable heat for the power block. The heat storage system stores solar energy from the solar field. It dispatches the energy to the power block when solar radiation decreases. The power block and grid connection uses the heat collected from the sun to produce electricity. It comprises a steam generator and a steam turbine coupled to a conventional synchronous generator and excitation system that generates electric power that is delivered to the HV or EHV grid by means of the plant’s own step-up transformer.

In a parabolic trough system, the solar field consists of hundreds of linear solar collector assemblies. The collectors form a horizontal modular array of long rectangular, U-shaped, highly reflective mirrors in parallel rows.

Each modular array has single-axis tracking, typically north-south, so that the array is always tilted toward the sun during the day. It focuses solar energy onto a central receiver tube located along the focal line of the mirrors, where it is absorbed. The receiver tubes are devices that are particularly highly radiation absorbent.

Inside them flows a working fluid called the heat transfer fluid (HTF), which exchanges heat from the solar field to the power block. The HTF is usually synthetic thermal oil (biphenyl oil) and is heated to temperatures of around 400 ºC. The HTF is pumped through a series of heat exchangers to generate superheated steam for use in a conventional steam turbine generator or is integrated in a combined steam and gas turbine cycle.

To increase CSP plant flexibility, the HTF can be stored in two devices that are particularly highly radiation absorbent. As a first approximation, the optimal limit shading angle for any specific site, the optimal ground area occupation ratio (GAOR) is the distance between the rows of PV modules in the solar field. The GAOR is affected by the shed disposition of PV modules in the solar field and the ground area occupied by the solar field. The GAOR is typically less than 1.5.

To compare a 50 MWp utility-scale, grid-connected PV plant with a 50 MWp CSP plant it is necessary to define common design bases by siting the plant in a specific area with a defined level of irradiation. This report puts both plants in the south of Italy.

In this region the yearly estimated average incident global irradiation is about 1900 kWh/m² per year for a fixed PV field with an optimum tilt of 30° and 2200 kWh/m² per year for tracker PVs. Yearly averaged direct normal irradiation is approximately 1800 kWh/m² per year.

The yearly average incident global irradiation is the effective radiation reaching the tilted PV module plane and is the sum of incident direct radiation, incident diffuse radiation from the sky and incident albedo radiation for a given reference year.

The yearly averaged direct normal irradiation is the yearly average amount of solar radiation incident on a surface in respect to the solar radiation for a given reference year.

4. IMPACT ON THE LANDSCAPE

4.1 UTILITYS-SCALE PV PLANT

The key factor in designing the utility-scale PV plant is to gain, for any specific site, the optimal ground area occupation ratio (GAOR) without a reduction in the expected performance ratio.

The GAOR is the ratio between the total surface of the PV modules in the solar field and the ground area occupied by the solar field. The GAOR is affected by the tilted disposition of PV arrays, which is the distance between the rows of PV modules. This depends on the array tilt angle and the limit shading angle. The array tilt angle mainly depends on the dimensions of the PV modules and their ability to capture and transform as much diffuse irradiance as possible. Thin-film modules are usually better than crystalline silicon modules.

As a first approximation, the optimal limit shading angle for latitudes in southern Italy corresponds to the angle – about 20° – needed to avoid shadows between 10 am and 2 pm at the winter solstice. The PV field performance increases slightly when shed distance increases for a given tilt angle. This is because shadows are reduced, especially in winter, which helps to reduce mismatch losses. Typical GAOR values for a fixed
installation in southern Italy are 0.4–0.6, which corresponds to a tilt angle range of 35°–25°. Lower tilts are often used for thin-film PV modules arrays because of their better response to diffuse irradiance.

With the tracker system the GAOR is in the range 0.2–0.3.

The corresponding ground area typically required for the same PV field in southern Italy amounts to 2.2–2.5 hectares/MWp (ha/MWp) if thin-film PV modules are used, and between 1.7–2.1 ha/MWp if crystalline silicon PV modules are used. The efficiency of crystalline silicon PV modules is better than the efficiency of thin-film PV modules. Typical respective ranges are 14–16 per cent and 10–12 per cent.

On the basis of these figures the estimated ground area needed to build a 50 MWp utility-scale PV plant amounts to 120–140 ha for a fixed PV field comprising thin-film PV arrays and to 90–110 ha for a fixed PV field comprising crystalline silicon PV arrays.

In the case of a tracker PV field, the required ground area amounts to around 4–4.5 ha/MWp if thin-film PV modules are used and 3–3.5 ha/MWp if crystalline silicon PV modules are used.

Even if these different technologies and arrangements are in a competition in which there are no clear winners, an observation to make is that, in terms of land impact, a fixed PV field requires about half of the area needed by a tracker PV system. The selection of PV modules may play an important role in determining the area required by the plant. Therefore the conclusion to draw is that, for large utility-scale PV plants, the fixed PV field arrangement is preferable in terms of impact on land.

4.2 PERFORMANCE

4.2.1 UTILITY-SCALE PV PLANTS

To maximize exposure to sunlight PV plants are designed by selecting the optimal tilt angle and azimuth angle and thus avoiding, as much as possible, shading between PV arrays. The energy produced by a PV system depends on:

- Solar radiation incident on the plane of the modules, which depends on:
  - The latitude of the installation site
  - The front-surface reflectance of photovoltaic modules
  - The exposure of modules, which depends on the tilt angle (the angle between the horizontal plane and the plane of the module surface) and the angle of orientation (the azimuth angle)
  - Any shade or fouling of photovoltaic modules;
  - Ambient temperature

- The characteristics of the modules (power rating, temperature coefficient)

- Mismatch losses due to inverter mismatch and non-homogeneous characteristics of modules connected in series and parallel, etc;

- The characteristics of the balance of system, such as the efficiency of the inverter, losses in the cables and diodes, etc.

Variations in solar radiation and ambient temperature from month-to-month and year-to-year influence performance parameters. The electricity produced by the utility-scale PV plant can be determined according to the method defined by the EN 61724 standard, which defines the overall PV system performance with respect to energy production, solar resource and overall effect of system losses. These parameters are the final PV system yield, Yf, the reference yield, Yr, and the performance ratio, PR. The performance ratio, PR, is dimensionless. It is Y divided by Yf. Y represents the number of hours that the PV arrays would need to operate at their rated power to provide the same energy and is expressed in hours or kWh/kW, while Yf represents an equivalent number of hours at the reference irradiance.

Y defines the solar radiation resource for the PV system and is a function of the location and orientation of the PV array, and month-to-month and year-to-year weather variability.

The expected performance of a 50 MWp utility-scale PV plant localized in southern Italy is shown in Table 1. The tracker PV system produces about 20 per cent more energy than a fixed PV on a yearly basis with the same nominal installed power.

CLICK TO VIEW TABLE 1:
UTILITY-SCALE PV PLANT PERFORMANCE.
4.2.2 CSP PLANT
As in a utility-scale PV plant, the performance of a CSP plant is affected by variations in solar irradiation, the characteristics of solar collectors and geometrical factors such as shadows. For CSP plants an efficiency factor, the so-called ‘capacity factor’ of the plant, can be defined. This is the ratio of the energy produced by the plant over the course of the year to the output had the system operated at its nameplate capacity, for example the nominal size of the steam turbine over 8760 hours.

The capacity factor depends strongly on the solar resource available in a certain location, on the solar field size and the area of the mirrors. Increasing the size of the solar field allows the plant to provide more thermal energy to the power block and consequently results in a higher capacity factor but also leads to an increase in investment costs. On the other hand, if the solar field area is reduced, a consistent part of the potentially available solar energy has to be dumped during high solar radiation days because the thermal energy to the power block is beyond the steam turbine maximum admissible thermal input.

The expected performance of a CSP plant of this size in southern Italy is shown in the following table.

CLICK TO VIEW TABLE 2: CSP PLANT PERFORMANCE TABLE

4.3 INTERACTION WITH THE GRID IN STEADY-STATE AND TRANSIENT CONDITIONS

4.3.1 SOLAR PLANTS AND GRID EXPLOITATION CONSTRAINTS
The worldwide liberalization of electrical power generation has brought the issue of market equilibrium to the attention of the power industry. All generating companies have to compete by exercising their market power by trying to maximize their profits. However, the competition from solar power generation, especially from utility-scale PV plants, may affect the bidding strategies of conventional generating firms, which could have an impact on nodal prices and profits.

The presence of solar power generation gives a conventional generating company incentives to exercise its market power in a different way than if its entire generation output were based on conventional power plants only. This changes the market. In the presence of solar generation, conventional generating companies would be forced to decrease their bidding parameters in order to cope with the increased availability of supply. Hence since solar plants are operated in a competitive manner, the market clearing price is reduced, thus social welfare is increased.

On the other hand, at a time when there is inadequate solar irradiance for the solar plants to generate power, conventional generating companies may take advantage of the lack of supply and alter their bidding strategies in order to force the nodal prices to increase, thus increasing their profits.

Considering that the European Union (EU) has set very ambitious targets for the penetration of renewable power generation, one expectation is that the implementation of multi-megawatt solar plants may cause problems regarding market prices.

This issue may be worse if the network to which the solar plants are connected have bottlenecks that cause congestion, for example the overloading of lines that, for reasons of safety, oblige connected solar plants to reduce their outputs. Furthermore this effect would be more severe in southern Europe or islands without suitable interconnection with the continental grid because of unfavourable weather conditions, especially in the case of PV, which is affected by temperature, and better irradiance can have a crucial impact on the amount of power produced.

Large-scale integration of multi-megawatt solar plants – especially utility-scale PV plants – into grid operation would therefore lead to new operational constraints for the entire HV transmission and distribution system.

For example, power is produced during the day, when electricity demand is high, thus it is valuable peak current. That could become unacceptable in the coming years in terms of grid and generating plant system performance. This would require a rethink about both the grid exploitation modality and of the design of solar plants, including, for example, an appropriate storage system.

4.3.1.1 CSP PLANT THERMAL STORAGE SYSTEM
The optimum solution for maintaining a high capacity factor and constant power production is the adoption of heat storage technology.

With heat storage, the energy excess from the solar field can be stored and dispatched to the power block when there is a lack of solar radiation. Theoretically CSP plants with substantial heat storage can achieve a capacity factor of 100 per cent, and may provide baseload electricity as conventional fossil fuel plants do. In other words, at a time when the sky is momentarily cloudy or even in the first few hours of night a CSP plant may operate by putting to use the solar energy previously stored.

Depending on the storage medium, the heat storage systems can be either direct, in which the storage medium is the same HTF circulating in the solar field concentrator, for example synthetic oil, or indirect, in which, for example, synthetic oil is used as the HTF and molten salts form the storage medium.

Advanced heat storage systems are under development. Today the most commonly used and commercially available heat storage technology for the parabolic trough plant is two-tank indirect thermal storage.

The two-tank indirect system is based on two tanks typically filled with molten salts (60 per cent sodium nitrates and 40 per cent nitrates) and heated to temperatures of around 390°C.
4.3.2.1 ACTIVE POWER CONTROL (DISPATCHING) AND REMOTE SET-POINT CONTROL

To avoid network congestion in the case of line loss because of an electrical fault all renewable generating units, such as utility-scale PV plants and CSP plants, have to reduce their power output. A transmission system operator (TSO) can require curtailment of the power output of solar power plants when faced with specific critical system conditions. CSP plants may face different requirements than utility-scale PV plants because the CSP looks like a conventional generating plant using a rotating synchronous generating unit whereas a PV plant uses a static inverter.

The power output of PV generating plants has to be reduced in steps of 10 per cent per minute, under any operating conditions and from any working point to a maximum power value (the target value).
which could represent a power reduction of 100 per cent. This has to occur without disconnection of the plant from the network.

Such a requirement may also be applied to CSP plants if they are considered in all respects to be renewable generating units. Otherwise they have to fulfil requirements set for conventional generating units, which have to reduce or increase output at different ramp-rates, for example 1 per cent/min, as required by German transmission [1], between the minimum stable generation power and the continuous output.

CSP plants may fulfil the requirement set for the PV generating units provided that the setpoint given by the TSO is compatible with the minimum operating load of the boiler and steam turbine. The characteristics of the CSP plant are similar to those of the traditional thermal power plant. This means the load reduction can reach values of around 40 per cent of the nominal capacity.

The limiting factor is the stable operation of the heat exchangers. The advantage of CSP is that, in the case of temporary reduction, limited to a few hours, the solar energy captured by the solar field is not lost. This is because it can be stored in the thermal storage system, but the amount stored depends on conditions such as the storage capacity, the actual operating conditions and the amount of sunshine.

For utility-scale PV plants such requirements are not an issue provided that an automatic power sharing management system is installed and it is capable of modulating the production of the entire plant by acting on each inverter through a communications-based solution by transmitting new power output setpoints or shutdown commands to disconnect several inverters or by combining the two controls. Of course, if a battery storage system is not installed, energy equivalent to the amount by which power is reduced is not lost. This is because it can be stored in the thermal storage system, and with the required ramp-rate.

So from a technical point of view there are no barriers preventing CSP and utility-scale PV plants from complying with such grid code requirements. However, there may be a rise in costs for PV plants in the implementation of a power sharing management system.

### 4.3.2.2 AUTOMATIC REDUCTION OF ACTIVE POWER GENERATION ACCORDING TO ACTIVE POWER DROOP CHARACTERISTICS IN SITUATIONS OF OVER-FREQUENCY

To avoid the risk of unstable system operation when the frequency rises above a certain value, any renewable generating unit, such as utility-scale PV plants and CSP plants, must be able to reduce the amount of power they generate when the grid frequency exceeds a pre-set value. A reference value for the active power reduction, $\Delta P$, is a larger percentage of the currently available power generation value at the point when the grid frequency is equal to 50.2 Hz.

This active power reference value must be reduced according to a coefficient, given as output percentage per Hz, when the grid frequency deviates from the pre-set value. The German transmission code requires all renewable-based generating units to reduce active power with a gradient of 40 per cent of the plant’s instantaneously available capacity per Hz, as shown in Figure 3. Requirements concerning power output adjustment and time duration may differ from country to country and depend mainly on local network conditions.

**CLICK TO VIEW FIGURE 3:**

**ACTIVE POWER REDUCTION OF RENEWABLE-BASED GENERATING UNITS IN THE CASE OF OVER-FREQUENCY**

Furthermore the generating units have to remain connected to the grid, without tripping, if either the grid frequency increases to 51.5 Hz or decreases to 47.5 Hz. Above 51.5 Hz and below 47.5 Hz the plants can be disconnected.

These requirements can be fulfilled fairly easily by the utility-scale PV system. A new control scheme has to be included in each inverter to control the operating point of a string of PVs and thus the power output. The inverter will automatically reduce the power output to a constant value until the frequency drops below the preset value. The inverter will then increase the power output automatically, switching to maximum power point tracking control.

CSP plants can easily fulfil such requirements. Because they can in all respects be considered as conventional generating units they could also provide primary frequency control, provided that the whole plant control – the steam turbine, steam exchangers and thermal storage system – is capable of operating in droop mode and with the required ramp-rate.

This coordinated regulation requires contemporaneous reaction of the steam turbine control system, which acts on the inlet steam control valves, and of the steam exchanger control system, which acts on feed-water flow and hot fluid flow, to meet the fast response and wide variations required by the frequency control. CSP plants may also use an appropriate thermal storage system to provide ancillary services such as secondary frequency control and minute reserve.

### 4.3.2.3 MINIMUM POWER FACTOR AT CONNECTION POINT, REACTIVE POWER CONTROL AND SET POINT CONTROL FOR VOLTAGE STABILITY, AND REMOTE CONTROL BY NETWORK OPERATOR

Slow variations in network voltage have to be kept within acceptable limits. Should operational requirements need it and at the demand of the system operator, any renewable generating unit, such as a utility-scale PV plant or a CSP plant, has to support the network voltage by injecting into the grid the appropriate amount of reactive power. This has to be in accordance with the request of the network operator.

Utility-scale PV plants installed today are designed to produce active power only. Reactive power is avoided because of losses in the inverter, lines and transformers. To meet the requirements of...
the grid codes, the inverters of the utility-scale PV plant have to be designed to be bigger, or a centralized static VAR compensation system has to be installed. Reactive power has only to be provided during feed-in operation, so there is no need to provide reactive power during the night. Overall an increase of PV installation system costs can be expected.

CSP plants can fulfil the requirements for minimum power factor and reactive power control because they use synchronous generators equipped with excitation systems capable of providing reactive power as required. Therefore the amount of reactive power that can be delivered to the grid mainly depends on the size of the generator and the excitation system, as in the case of conventional generating units.

In addition, because they may in all respects be considered as conventional generating units, CSP plants may be requested to provide different amounts of reactive power during different voltage situations. Apart from the requirement to provide reactive power at the nominal design point of the generating unit (P = Pn), there would also be a requirement concerning operation at an active power output below the nominal active power (P < Pn).

In this case a CSP plant may be requested to operate its generator at every possible working point in accordance with the generator output diagram. The nature of the request can vary according to the situation on the network. This implies that the provision of reactive power takes precedence over the supply of active power.

4.3.2.4 Behaviour in the Event of Network Disturbances

Any renewable generating unit is required by the German code to support the grid during the transients. The code puts renewable generating units into two categories: those based on synchronous generators and the rest. Both categories are required to contribute dynamic support according to their capabilities. Since the CSP can in all respects be considered as a conventional generating unit, it should meet the same requirements that conventional generating units have to meet. All other renewable generating units, such as PV systems, have to meet other requirements as this paper will now describe.

During a network event and its consequent voltage drop, a PV plant has to remain connected to the grid and to inject a certain amount of short-circuit current into the network. The amount is agreed with the network operator on a case-by-case basis. The plant also has to feed in the same amount of active power as soon as the fault is cleared and to absorb the same or a lesser amount of reactive power.

The code specifies the voltage drop that will be ridden through by any PV generating plant (the voltage-through capability), as shown in Figure 4. Above ‘borderline 1’ the generating units must remain connected. Above ‘borderline 2’ and below ‘borderline 1’ generating units have to remain connected even if they are not capable of supporting the voltage network. Below ‘borderline 2’ the generating units are allowed to be disconnected.

CLICK TO VIEW FIGURE 4:
LIMITING CURVES OF VOLTAGE AT THE GRID CONNECTION POINT IN THE EVENT OF A NETWORK FAULT

As shown in Figure 5, different fault ride-through capability requirements are specified by the different grid codes of European countries [7]. The fault ride-through capability curves are quite similar, but the dynamic requirements are different, mainly with respect to voltage support during a voltage drop.

CLICK TO VIEW FIGURE 5:
COMPARISON OF THE FAULT RIDE-THROUGH CAPABILITIES REQUIRED BY DIFFERENT GRID CODES IN THE EVENT OF NETWORK FAULT

The German transmission code requires PV generating plants to support the network voltage by injecting additional reactive current during the voltage drop. The control systems of the PV generating units have to allow an appropriate voltage control strategy, as shown in Figure 6. This will be activated in the event of a voltage drop of more than 10 per cent of the effective value of the generator voltage.

This voltage control must ensure the supply of reactive current at the low-voltage side of the generator transformer – in other words, at the inverter output terminals – with a contribution of at least 2 per cent of the rated current per percentage point of voltage drop. PV generating units must be capable of feeding in the required reactive current into the network within 20 milliseconds. They may have to supply reactive current of at least 100 per cent of the rated current.

CLICK TO VIEW FIGURE 6:
THE PRINCIPLE OF VOLTAGE SUPPORT IN THE EVENT OF NETWORK FAULTS

These requirements do not influence the dimensioning of the PV inverter but do have an impact on the control algorithm.

CSP generating plants can be considered to be conventional generating units, especially those based on parabolic trough technology. Therefore the voltage support during voltage drop can be achieved easily through proper design of the generator and the excitation system.

5. Conclusions

Referring to a typical case of a 50 MW solar plant to be built in southern Italy, utility-scale PV plants are preferable because of their smaller footprint. For example, the area required by a utility-
scale PV plant of the fixed type and based on crystalline-silicon PV modules, is about 50–55 per cent lower than the area required by a CSP plant with the same nominal power.

Furthermore siting a utility-scale PV plant is usually easier than siting a CSP plant because it does not need flat land; it can be installed on a sloping site. Unlike a CSP plant, the modular utility-scale PV plant usually comprises several power blocks of 1 MW and can easily be expanded as demand increases.

Finally a PV plant can be built in a shorter time-frame than a CSP plant provided that the materials, mainly PV panels, are available and all permits already gathered. The time needed to build a 50 MWp utility-scale PV plant is 14–16 months. To build a 50 MWc CSP would require 24–36 months. PV arrays are fairly easy and quick to install while CSP is much more like a conventional power plant, particularly in that part of it that concerns the steam process.

On the other side, in terms of grid impact, utility-scale PV plants are not naturally suitable for the supply of predictable energy or to provide network ancillary services unless special control features or additional equipment are designed and installed – such as a battery storage system and the capability to have the inverter respond to frequency and voltage – with a consequent increase in capital costs.

CSP generation, on the other hand, is highly predictable and since a CSP plant is intrinsically coupled to thermal storage, it can easily meet the load demand curve at any time during the day and the first few hours of night. It can also cover peak hours demand if scheduled.

Furthermore, CSP plants can easily participate in primary and secondary grid frequency control. This means they can support grid exploitation during both steady-state and transient conditions.

New grid codes have recently been issued in some European countries. These have to be considered as important steps towards reliable interaction between renewable generating plants and the electrical network even if these codes are not yet harmonized Europe-wide.

There are different approaches to “minimum mandatory requirement” and “ancillary service”, depending on the technical needs of the specific power system, and the legal and organizational structures of different TSOs, which have historically established grid management procedures.

A barrier is in the way of deployment of utility-scale PV plants. Unlike CSP plants, PV plants need a special and costly design to comply with the different needs of the grid.

This paper recommends that all technical requirements are thoroughly investigated inside CEN/CEC (European Committee for Electrotechnical Standardization) technical committees in order to achieve clearly defined and, perhaps, harmonized rules, at least within the European market, that can bring into line the different interests of manufacturers, power producers and network operators, and minimize capital costs.
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1. INTRODUCTION

The decarbonization of European power generation is one of the key challenges to be addressed in the coming years. In the past, a well-balanced mix of fossil, nuclear, and renewable energies has been used to supply the required electricity any time, any place. To guarantee high reliability of supply in fluctuating demand situations, a mix of baseload (nuclear, hydro, and coal), mid-load (coal and gas), and peak load (gas and [pumped] hydro) power plants has been used. In recent years, the broader uptake of renewable energies such as wind and solar has contributed positively towards decarbonization but has thrown up new challenges in energy supply.

Compared with fossil fuel options, which could be decarbonized using carbon capture and storage, the operational fluctuation of wind and solar power generation is directly linked to the weather, which cannot be influenced or controlled by power companies. Increasing electricity generation from intermittent renewable energy sources therefore requires new approaches to balancing supply and demand. These have to take into account regional and cross-border restrictions in the transmission and distribution grid to enable a stable and secure electricity supply, even at high inputs of renewable electricity generation.

Energy storage has been identified as a key solution for coping with these challenges. However, the possibilities of extending pumped hydro capacities are limited in Europe due to topographic restrictions. Such plants are typically not located in regions where high wind electricity generation is expected in the future, the North Sea in particular. A technical analysis of potential large-scale energy storage technologies in the future has shown that besides pumped hydro and compressed air energy storage (CAES), no other large-scale energy storage technologies are available on the market for the time being.

Compared with pumped hydro storage, CAES has disadvantages in terms of operational costs, cycle efficiency, and possible storage capacities, but it would be more suitable to the geology of northern Europe with its salt dome formations. Yet today only two CAES plants are in operation worldwide, one in McIntosh in the US, commissioned in 1991, and one in Huntorf, Germany, the world’s first CAES plant, commissioned in 1978 and operated by E.ON.

So being aware that the increase in renewable energy supplies will result in a stronger requirement for energy storage, EDF, EnBW, E.ON and RWE decided in 2009 that it would be valuable to analyze possible future developments of the electricity market and opportunities and risks for CAES systems in an energy system with an increasing share of renewable energies.

A detailed look at possible revenue opportunities for large-scale CAES in the future that make use of the spot market and rely on the provision of grid services in the form of positive and negative minute reserve have been undertaken for the period until 2050. Different scenarios have been commonly defined, and the economics of diabatic and adiabatic CAES configurations have been analyzed under the different scenario assumptions.

This paper describes the approach used and the main findings of the analysis. All in all, the results look promising for the deployment of CAES technologies but there are still technical challenges that have to be addressed to make adiabatic CAES feasible. The focus of the analysis was on the German electricity market but the analysis takes into account the development of the electricity market in Europe as a whole.

2. CAES FOR LARGE-SCALE ENERGY STORAGE

The scope of our study was to analyze the economics of diabatic and adiabatic CAES in future electricity markets.
Table 1 shows the advantages and the disadvantages of both technologies.

**CLICK TO VIEW TABLE 1: COMPARISON OF ADIABATIC AND DIABATIC CAES**

For our study we have analyzed three technical settings of CAES systems (see Table 2). All configurations can provide four full load hours of output operation. Two different configurations of diabatic CAES were considered to have a better comparison with adiabatic CAES. While CAES-1 and AA-CAES have an identical compressor size, CAES-2 and AA-CAES require the same time to fully load the storage, approximately ten hours. For all configurations we assumed a variation of the cavern pressure of 41–58 bar.

**CLICK TO VIEW TABLE 2: POWER RATINGS AND STORAGE CAPACITIES OF ANALYZED CONFIGURATIONS**

The cost estimate is based on an analysis of data available in literature on compressors, expanders, subsurface caverns and the required heat storage device for the adiabatic case. The economic analysis has also taken into account technical limits and cost factors, such as startup costs and part load operation. The heat storage loss is assumed to be about 2 per cent per day. Due to the expected limited number of calls in the minute reserve market it is important to factor in such parameters.

**CLICK TO VIEW FIGURE 1: STRUCTURE DIAGRAM OF THE MODEL-BASED ANALYSIS**

The multi-periodic energy model provides a detailed representation of the existing European electricity supply system with its specific techno-economic characteristics and constraints. The model (see Figure 2) comprises a large variety of fuel resources (for example gas, coal and lignite) and non-fossil fuel resources (for example nuclear), including renewable energy resources (such as wind, solar, biomass and waste).

**CLICK TO VIEW FIGURE 2: GENERALIZED INVESTMENT MODEL STRUCTURE**

**3.1 SCENARIO DESCRIPTION**

Five consistent energy scenarios had been defined to cover a variety of possible developments of future energy markets.

- **Moderate Case (MOD):** Based on current policy commitments for renewable energy targets and emission reduction targets and moderate fuel prices.
- **Climate Case (CLIM):** Compared with MOD there are higher renewable energy targets and more ambitious emission reduction targets. The same development of fuel prices is used as in MOD.
- **Climate Case B (CLIMB):** For this scenario, the same emission reduction targets as in CLIM were set. However, the renewable targets are the same as in MOD, so that the environmental targets remain achievable by alternate means and technologies.
- **Resource Case (RES):** The key parameter of this scenario is the sharp increase in energy carrier prices. As a consequence, a decreased electricity demand is assumed. The renewable energy targets are the same as in the MOD scenario.
- **Nuclear Case (NUKE):** Regarding the German market, a revision of the nuclear phase-out is assumed. The environmental and renewable targets are the same as in MOD. The energy carrier prices are lower than in the MOD scenario.

The development of energy carrier prices in the various scenarios is based on existing studies. The low-price scenario (NUKE) is based on the prices published in [1] and the high-price scenario (RES) is based on [2]. The prices published in [3] are used for the moderate and climate scenarios. Since most existing studies have a time horizon limited to 2030, the price trends were extrapolated to 2050.
For the development of electricity demand in the different scenarios we have used the values listed in Table 3. In comparison, the electricity demand projection in [3] amounts to 3469 TWh for 2015 and 3980 TWh for 2030.

4. THE AGENT-BASED POWER MARKET MODEL

The used model is a multi-agent-based simulation model of the German electricity market. It simulates the behaviour of the main actors in the electricity sector as software agents. Agents can be end customers, electricity utilities, producers of renewable energies, transmission systems operators (TSOs), distribution system operators and the government. Some actors are represented by multiple agents because of their complexity.

A typical example is the representation of electricity utilities. Each of the different agents of an electricity utility represents a different role in the company. For example, there is an agent who is responsible for the management of power plants and an agent who is responsible for trading electricity on the spot market.

A detailed description of the agent based model use is given in [4] the simulation operates on an hourly time resolution to simulate auctions such as the spot market, which operates with hourly prices. This means that demand side and renewable electricity generation has to be provided on an hourly time resolution. Figure 3 gives an overview of the agent-based model. The model follows a modular design with separate modules for the supply side, the demand side, the markets, renewable electricity generation, etc.

4.1 REPRESENTATION OF RENEWABLE GENERATION

The detailed representation of renewable electricity generation is a central part of the model. The data provided on an hourly time resolution are stored in a database containing load profiles, utilization data and the installed capacity for ten renewable energy technologies. These are: onshore wind, offshore wind, small hydro, large hydro, biomass, biogas, sewage gas, landfill gas, photovoltaic and geothermal.

An important issue for the simulation of renewable electricity generation is the provision of hourly load profiles. Due to the high installed capacity and the fluctuating character of the load profile of wind energy, these load profiles had been calculated with a separate model using available meteorological data (wind speed, temperature and atmospheric pressure) provided by Deutscher Wetter Dienst, covering the years 1998, 2000 and 2001, and technical data from manufacturers. The years represent a good year (1998), an average year (2000) and a bad year (2001) for wind in which the differences reach more than ±10 per cent of average energy production. For the other renewable technologies, historical load profiles have been used in the simulations computed.

4.2 WIND MODEL

As wind energy, which fluctuates, is expected to be a key driver for renewable energy development, the electricity production from wind has been modelled in more detail than for the other renewable electricity generating technologies. The basic approach in the wind model is the calculation of electricity production based on the power of the wind multiplied by the power coefficient of the specific wind turbine. For each turbine type and location, the power production is calculated using wind speed measurements from around 180 locations (see Figure 4) with an average time resolution of ten minutes.

5. POSSIBLE REVENUE FLOWS FOR ENERGY STORAGE

To be able to participate in the balancing power market, the power units have to pass through a prequalification process. The technical properties that are required to pass this process are different for
The electricity price is the strike price of the call option. It is holding the capacity ready. It is paid in case a bid is contracted.

€/MWh. The capacity price is a call premium which is paid for 15 minutes.

- Must be able to fully supply the contracted capacity within a day.
- Six time slices per day of four hours each.
- Minimum capacity bid: 15 MW.
- Day-ahead, pay-as-bid auction.
- Common German market of all four TSOs.
- The TSOs have introduced such a market which is traded on a monthly basis.

The wind reserve market is not organized as a common German market and the capacities traded in these markets are small. For example, in 2008 the monthly average demand for positive wind reserve was 300 MW in the RWE control area and 150 MW in the Vattenfall control area. These markets are unlikely to further develop as the German regulatory office, Bundesnetzagentur, has stated repeatedly that it would like to see TSOs balance out wind power in the day-ahead spot market and in the intraday market by the end of 2010 at the latest.

In the following analysis the focus was therefore on the day-ahead spot market and the minute reserve market. Both products traded on a daily basis in the market.

5.1 MINUTE RESERVE

The regulatory framework of the German minute reserve market was set by the Bundesnetzagentur in 2006 [5]. The main conditions of the current regulatory framework are:

- Common German market of all four TSOs
- Day-ahead, pay-as-bid auction
- Minimum capacity bid: 1.5 MW
- Six time slices per day of four hours each
- Must be able to fully supply the contracted capacity within 1.5 minutes

Bidding is only allowed for selected time slices. Each bid must include a capacity price in €/MW and an electricity price in €/MWh.

The capacity price is a call premium which is paid for holding the capacity ready. It is paid in case a bid is contracted. The electricity price is the strike price of the call option. It is paid only in case the contracted capacity is actually needed as balancing power on the following day. The bid selection process is a two-step process. In the first step, the bids to be contracted are identified based solely on their capacity price. All bids are ordered by their capacity price in ascending order. Then bids are contracted until the TSOs’ demand is satisfied. The demand to be contracted is announced by the TSOs before the auction.

Figure 7 gives an overview of the paid capacity prices for positive and negative minute reserve power during 2007 and 2008.

5.2 REACTIVE POWER

As a first step, the possible revenues that could have been obtained by a CAES plant have been analyzed based on the historical data of the minute reserve markets in 2007 and 2008. Positive and negative reactive power has been taken into account.

Therefore the average price for negative minute reserve is lower than for positive minute reserve. However, since fewer units are in operation during the weekend due to lower demand, the price for negative minute reserve is increasing during the weekend.

To evaluate possible revenue from the minute reserve market it is important to look at the amount and frequency of the reserve calls. Figure 8 shows the total number of calls by time slice and control area for the German market.

6. MODELLING RESULTS

As a first step, the possible revenues that could have been obtained by a CAES plant have been analyzed based on the historical data of the minute reserve markets in 2007 and 2008. Positive and negative reactive power has been taken into account.

6.1 CONTRIBUTION MARGINS BY PROVISION OF REACTIVE POWER

To calculate the possible revenues from providing positive or negative reactive power, a simulation was performed to calculate the contribution margin from both power types. The contribution margin from positive power was calculated as:
margin is calculated as the balance between income and variable costs. Fixed maintenance costs are not part of the variable costs. An optimistic and a pessimistic calculation has been made, taking into account the maximum price of the bids in the optimistic case and the minimum price of the bids in the pessimistic case.

**CLICK TO VIEW TABLE 4: CONTRIBUTION MARGIN FROM POSITIVE AND NEGATIVE MINUTE RESERVE MARKET**

6.2 CONTRIBUTION MARGIN FROM ACTING ON THE ELECTRICITY SPOT MARKET

The evaluation of the spot market electricity prices in 2007 and 2008 is shown in Table 5. The price in 2007 was mostly below €30 ($39) per MWh. In 2008, higher average prices have been achieved. However, there have also been 1.5 hours with negative prices. Negative prices had been allowed in 2007 by the EEX.

**CLICK TO VIEW TABLE 5: OVERVIEW OF SPOT MARKET PRICE CHARACTERISTICS IN 2007 AND 2008**

The three CAES plant configurations have then been utilized to make use of price differences at the spot market for generating a contribution margin. The CAES buys electricity at the spot market when the price is low and sells electricity when the price is high. The different efficiencies, the heat losses in the adiabatic case and the different operating costs have been taken into account. It should be noted that the adiabatic plant configuration not only generates revenues out of the spot market alone, but also out of the differences between the gas price and spot market price.

For all configurations the calculated discharging times for operation in the spot market of 2007 and 2008 would have been between 1000 hours and 1500 hours, with the lower number for the adiabatic case. Charging time would have been between 1300 hours and 3000 hours, the higher number for the CAES-2 configuration with the smaller compressor. About 300–400 start-ups for discharging had been computed by the model and about a similar number of starts for charging. Figure 9 shows an example of the dispatch of the adiabatic CAES configuration for Week 44 in 2008. The storage is charged if the electricity price is below €60/MWh.

As the model is aware of the future development of electricity prices, this type of dispatch is rather optimistic because, for example, the model knows that the price on Saturday morning will be low and therefore completely discharges the storage on Friday to make maximum use of the low electricity price, a strategy which could not be followed if the future market prices were not completely known.

**CLICK TO VIEW FIGURE 9: EXEMPLARY DISPATCH OF THE AA-CAES CONFIGURATION IN WEEK 44 OF 2008**

Based on the modelled dispatch on the spot market price, the contribution margin from acting on the spot market can be calculated for all CAES configurations. The results, shown in Table 6, prove that there is additional income from the spot market for the diabatic configurations, meaning more frequent operation. Due to low gas prices this leads, in the markets of 2007 and 2008, to higher contribution margins for the diabatic plant configurations. This effect is more important for the configuration with the large compressor (CAES-1) as charging times are shorter so that it can operate more frequently on discharging.

**CLICK TO VIEW TABLE 6: INCOME FROM OPERATION ON THE SPOT MARKET AND REFLECTIVE CONTRIBUTION MARGIN**

6.3 THE FUTURE DEVELOPMENT OF THE POWER PLANT MIX

The analysis of the markets in 2007 and 2008 shows that it would not have been possible to recover the full cost of any compressed air storage plant from the incomes generated by their operation. However, the income is clearly dependent on the price structures of the spot market and the market for minute reserve.

To get an understanding of the future chances of CAES it is necessary to look into the future. The development from 2007 to 2008 already indicates that contribution margins could change significantly, depending on the overall market development. So, in a first step, the development of the future power plant mix to 2050 was calculated for the different scenarios on a county level. Figure 10 shows the model results for Germany and Europe as a whole.

**CLICK TO VIEW FIGURE 10: CALCULATED POWER PLANT MIX IN EUROPE UP TO 2050 FOR EUROPE UNDER VARIOUS FRAMEWORK CONDITIONS**

The calculated power plant mix was then used to calculate the price curves, using the agent-based model, taking into account the fluctuating nature of wind and solar energy.

6.4 THERMAL REST LOAD

One good indicator for the possible development of the market is the calculation of the thermal rest load. The thermal rest load curve is obtained by reducing the consumption load profile by the electricity supply of the non-dispatchable renewable energies. This thermal rest load has to be satisfied by thermal power plants which are setting the electricity price on the market.
The thermal rest loads for the moderate and resource scenario are shown in Figure 11. In 2010, the thermal rest load in Germany always exceeds 15,000 MW. Looking further into the future, with an increase in renewable energies the thermal rest load significantly decreases over the years and even becomes negative for some hours of the year, meaning that electricity prices on the spot market will be most probably negative. However, the importance of this effect is linked to the scenario. In the MOD scenario the uptake of renewables is much slower than in the RES scenario, therefore in the RES case the thermal rest load is decreasing faster and stronger than in the MOD scenario.

6.5 ELECTRICITY SPOT MARKET PRICES UP TO 2050
The German electricity spot market is designed as a so-called day-ahead market. Here the auction takes place one day before physical fulfilment. The price mechanism of the auction is a uniform market price.

Market participants can make their buying or selling bids with specifications in volume and price limit until 0000 (midnight) on the trading day for each hour of the next day. According to the bids, the price is assigned for every hour of the following day, so the modelling was made on an hourly basis, and an hourly spot market price was calculated for all years and all scenarios.

Figure 12 shows the average electricity prices calculated with the model for different scenarios and target years. The average electricity price is not given in real terms as this could be misinterpreted, even if the value was calculated in detail. Instead, all values are expressed relative to the electricity price in 2010 for the moderate scenario. The highest average spot market price is calculated for the resource scenario and the lowest for the nuclear scenario.

6.6 ELECTRICITY PRICE SPREADS UP TO 2050
For the operation of energy storage systems, the absolute price levels on the spot market are only an indicator for developments. This is because energy storage plants do not generate revenues out of the spot market price itself but out of the spot market price difference at different moments in time. So the price spread between peak and off-peak prices will determine the potential income of storage plants. Figure 13 shows the results of the model calculations.

CLICK TO VIEW FIGURE 13:
DEVELOPMENT OF THE SPREAD BETWEEN PEAK AND OFF-PEAK PRICES
If we compare the results for the different scenarios for the peak and off-peak spread we can conclude the following:

- The NUKE case shows the lowest spread overall.
- The RES case starts with the highest spread. After 2020 it decreases, mainly because of the definition of the spread, which might not be appropriate any more in such scenarios.
- The MOD and Climate Cases show a similar spread up to 2030. After 2030 the spread decreases for the climate cases, especially for the second climate case which develops into a relatively single-sided, mainly gas-based generation mix.
- The MOD case shows a more balanced generation mix with a significant amount of lignite left in the generation mix.

The decreasing importance of the traditional definition of peak load time and off-peak load time in a system with a high share of renewables necessitates a modified definition of the price spread to be a more significant indicator for storage revenues in such systems. So to get a better understanding of the potential revenues from storage systems a new definition of the price spread has been used. The peak price has been defined to be the average price over the four most expensive hours of the day, and the off-peak price as the price averaged over the eight cheapest hours of the day. This corresponds to the technical configuration of the CAES storage system as we can discharge for four hours, and recharging will need about eight hours.

Applying the new definition of the price spread will give different results comparable to the traditional approach but would be more appropriate as an indicator for the potential revenues of a CAES system. Figure 14 shows the modelling results applying the new definition of the price spread. As might be expected, the average price spread between peak and off-peak electricity prices is significantly increasing.

CLICK TO VIEW FIGURE 14:
DEVELOPMENT OF PRICE SPREAD BETWEEN PEAK AND OFF-PEAK USING THE ADAPTED SPREAD DEFINITION
The difference in the price spread between the scenarios remains almost unchanged. The RES case shows the largest spread and
therefore the most favourable conditions for energy storage applications. However, in the RES case the price of natural gas is high, so the diabatic CAES system might not be economical.

7. SUMMARY AND CONCLUSIONS

The possible developments of market conditions for large-scale CAES have been analyzed for a period up to 2050. The results of the analysis show that the market in 2007 and 2008 was not ready for additional CAES storage capacity as it would not be possible to earn the full costs at the market, even when combining the revenues from acting on the spot market and on the minute reserve market.

However, the analysis up to 2050 clearly highlights that the future for CAES becomes brighter as market conditions change, and the share of fluctuating renewable energy to satisfy electricity demand increases. Electricity prices, as well as price spreads, will most likely increase over time. Peak and off-peak price definition should no longer be triggered by high and low electricity consumption but by high or low feed-in of renewable energies.

It should be noted that CAES would not be economical in all scenarios if only the revenues from the spot market are taken into account. CAES has also to deliver grid services such as minute reserve to reach economical operation. Even when taking both possible revenue flows into account, the net present value of such an investment would be negative in some scenarios. The picture is further complicated since diabatic and adiabatic CAES score differently depending on the chosen scenario assumptions.

CAES is one important technical option for large-scale energy storage and the better integration of fluctuating renewable energies in the electricity market. However, the market situation is highly insecure, therefore investment might not take place under market conditions. In addition, adiabatic CAES is not state-of-the-art. High-pressure, high-temperature air compressors and large-scale heat storage devices need to be further developed for commercial application.
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POWER-GEN EUROPE

TRACK 2

REDUCING THE CARBON FOOTPRINT OF FOSSIL POWER GENERATION
Alstom’s CO₂ Capture Technology Development – Update on Carbon Capture Technologies and Pilot Operation

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ABSTRACT
Power generation is one of the biggest sources of man-made carbon dioxide (CO₂) emissions. The combustion of fossil fuels plays a key role in global emissions of CO₂. This means that new technologies are required to enable the power sector to continue to meet the global demand for electricity while controlling carbon emissions and contributing to a reduction in the impact of global warming. To achieve meaningful emission reductions, it is necessary to develop technologies that can not only be applied to greenfield projects but can also be cost-effectively retrofitted to existing fleets.

This paper provides an update of Alstom’s development programme for oxy and post-combustion technologies. We present details on various field pilot and validation projects in operation worldwide and key results obtained from operation and testing programmes.

The development of CO₂ capture technologies is being pursued by European and US suppliers in collaboration with utility companies, academia, the US Department of Energy (DOE), the European Union (EU) and others. Alstom, with co-funding from various government and private organizations, electricity utilities and other industrial partners is developing, operating and testing different carbon capture technologies at power plants worldwide that burn both coal and natural gas.

The knowledge being gained from these projects is very encouraging and is a solid basis for the support of large-scale demonstration projects that are in development. This knowledge is taking Alstom closer to its goal of supplying commercial carbon capture technologies to the market by 2015.

1. INTRODUCTION TO CCS
In the World Energy Outlook 2009, the International Energy Agency (IEA) of Paris, France, provides a baseline estimate for the increase in long-term world power generation installed base. It says the rise should be approximately 73 per cent by 2030, and electricity generation will increase at the same pace. In this reference scenario, fossil fuels represent a major share of power generation in 2030. In that year, slightly more than two thirds of electricity generated will come from plants fired by coal, oil or gas. This will lead to a sharp increase in CO₂ emissions: about 50 per cent by 2030 to reach close to 18 Gigatonnes. Coal will still be the main contributor of CO₂ emissions in 2030, gas will be second.

The May 2007 IPCC Summary for Policymakers provides a maximum target of 450 ppm CO₂ equivalent greenhouse gas (GHG) concentration in the atmosphere to limit the rise in the earth’s surface temperature to 2 °C by 2100.

However, fossil-fuelled power plants will continue to be built worldwide, so achieving the 450 ppm target will require the deployment of a portfolio of solutions to address the challenge in the best technical and economical ways.

The CO₂ emission reduction objective of the power generation sector compared with the reference scenario is 9.3 Gigatonnes of savings over a total of 13.8 Gigatonnes. This saving comes from reduced demand, further development of renewables, further nuclear deployment, use of more efficient coal and gas power plants and carbon capture and storage (CCS), which will account for a reduction of 1.1 Gigatonnes of CO₂ per year in 2030 and 5.5 Gigatonnes CO₂ per year in 2050. These figures are from the IEA’s Technology Roadmap, Carbon Capture and Storage of 2009.

The most promising solution for dealing with fossil fuel emissions from the power sector is CCS. Among the three families of capture technologies envisaged, post-combustion and oxy-combustion are expected to become commercial from 2015, from which date they will be able to address both new power plants and existing fleets.

For more than ten years, strong efforts have been made to put into the development of CCS technologies, starting...
Jean-François Leandri accepted the award on behalf of Philippe Paeflinck.
with R&D and laboratory pilots and, in recent years, through multiple partnerships worldwide that have built and tested pilot and validation projects. Successful tests and very promising results from these projects are beginning to pave the way to the commercialization of products.

This paper presents the progress of the development of CO₂ capture systems in various pilot and validation plants. It focuses on those in which Alstom has participated. This paper will also explain the remaining challenges facing the key next step: large demonstration projects.

Among the challenges that CCS faces is optimization of the costs and performances of the power plants equipped with CCS. This is the key to balancing the resulting increased cost of electricity with the current and future cost of CO₂. This paper will also explain how an integrated approach can be one way to mitigate the global cost of electricity and can bring other benefits.

2. STATUS OF CCS DEVELOPMENT

CCS in the power generation sector can capitalize on a series of component technologies that have been developed and have been in commercial use in the oil & gas industry for decades. Capture technologies, which are early on in the CCS chain, which included CO₂ capture, transport and storage, have for decades been used in industries such as that for the processing of natural gas. Although the components are mature, the application of these technologies in the power sector is new and has some technical and scaling-up challenges, but they do not represent fundamental research (see Figure 1).

CLICK TO VIEW FIGURE 1:
MCKINSEY CARBON CAPTURE & STORAGE: ASSESSING THE ECONOMICS, 2008

There are various capture technologies under development. The closest to commercial stage are post-combustion, oxy-combustion and pre-combustion. We will provide an example of the development path that capture technologies can take. Onshore pipelines have been used to transport CO₂ since the 1970s. They carry the gas from industrial or natural sources to oil fields to be used to increase oil production through enhanced oil recovery (EOR) projects. In the US alone, more than 5000 km of CO₂ pipeline is in operation today and experiences no major difficulties. When it comes to deep geological storage of CO₂, EOR is advanced because of large-scale operations in the US. Other options, such as pure storage in depleted oil and gas fields, or the promising saline aquifers are slightly less advanced. Numerous large demonstration projects are operating, such as Sleipner, Snøhvit and Otway. All component technologies, especially in the field of monitoring, are well developed today.

The first demonstration CCS projects of pre-commercial size are coming online. Behind them is a significant pipeline of large projects, of size greater than 100 MW, which will represent the completion of the development of CCS technologies.

As of January 2010, published listings and internal Alstom data have allowed us to identify 67 credible large CO₂ potential demonstration projects worldwide in various stages of advancement. While limited information is available on these projects, we estimate that they already account for 15-20 GW of CO₂ potential. The first conclusion is that this represents a huge effort by the industry to scale up the necessary technologies and make them available as soon as proper regulation drives their installation.

Just over half of these projects, or 35 out of 67, are in Europe because of a UK competition and the pre-announcement of 10-12 EU Flagship programmes, which have triggered considerable interest and pre-feasibility studies. A second conclusion is that early government signals on CCS funding are attracting enough interest from the industry for the first phase of deployment.

The three most advanced technologies are all represented in these projects (see Figure 2). This leads to the third conclusion that the EU recommended technology portfolio approach to determining the costs of large-scale projects can be applied worldwide. Most of these large-scale projects, 54 out of the 67 identified, are new. However, addressing the installed base in this early ramp-up period is also necessary.

CLICK TO VIEW FIGURE 2:
BREAKDOWN OF ANNOUNCED LARGE-SCALE DEMOS

It also appears from this analysis that more projects use post-combustion technology – 34 out of 68 projects – than pre-combustion or oxy-combustion. This is related to the ability of post-combustion to allow partial-flow capture, enabling the targeting of large plants while minimizing investment – as no boiler modification is needed – and risks during the demonstration phase. However, this distortion will disappear at the commercial stage and oxy-combustion should ramp up at a similar rate to post-CO₂ emission reduction.

Retrofitable CCS technologies such as post and oxy-combustion seem logically to be the preferred options for the early ramp-up of the CCS market and experimental operation of the full CO₂ value chain. These large-scale projects are a step toward commercialization and they capitalize on the experience gained by the industry in pilots and demonstrations of smaller size that have tested CO₂ capture, transport and storage.

3. GOING COMMERCIAL: THE ALSTOM EXAMPLE

The development and introduction of a new technology by its
Alstom has already concluded partnerships concerning the chilled ammonia process:

- At Pleasant Prairie, a hard coal pilot plant, for We Energies in the United States, in association with the Electric Power Research Institute (EPRI). This ended operation on 31 October 2009 and was considered a great technical success. The pilot plant processed a 5 MWth equivalent slip stream of flue gas and captured CO₂ at a rate of 15 000 tonnes per year. A test programme there was recently completed and we present the main results later in this paper.

- A pilot at the E.ON Karlskrona plant in Sweden. While similar in size and design to the We Energies pilot, the operation of this pilot offers additional depth to Alstom’s development programme. This pilot captures CO₂ from an oil fired boiler with high SOx and NOx emissions. Design improvements are integrated in the water wash system. This pilot plant is also equipped with additional instrumentation that will refine Alstom’s understanding of the process.

- A validation pilot testing at AEP Mountaineer in partnership with American Electric Power. The 54 MWth unit is of a size that allows it to capture more than 100 000 tonnes of CO₂ per year from flue gas from the combustion of bituminous coal. It began operation in September 2009. A test campaign started there recently and the first results should be available in the coming months.

- A 40 MWth validation facility in Mongstad for which an EPC contract was signed with TCM in Norway, a group of companies that includes Statoil. The unit will capture 80 000 tonnes of CO₂ per year from flue gas from a gas fired plant. This facility is under construction and is expected to be commissioned in August 2011. Figure 5 illustrates the facility, which Alstom will design and construct.

Click to view Figure 4: Charleston Field Pilot

3.2 Chilled Ammonia, Small and Medium-Scale Pilots

As of January 2010 six pilots were operating and providing experience of their technologies whereas six others were at the evaluation, engineering or construction phase (see Figure 3). We now describe the small and medium-scale pilots that are in operation or in construction, by technology. We show what knowledge has been gained from the few pilots that have already been tested extensively. We then briefly describe the large-scale demonstration plants.

3.1 Advanced Amine, Small to Medium-Scale Pilots

Alstom and Dow Chemical Company announced in February 2008 a joint development and commercialization agreement concerning the advanced amine process (AAP). The agreement covers advanced amine scrubbing technology for the removal of CO₂ from low-pressure flue gases in power plants fired by fossil fuel and from plants in other major industries.

An industrial pilot is running at a coal fired power plant in the Dow Chemical plant in Charleston, West Virginia, USA. The pilot is using UCARSOL FGC 3000 solvent to process flue gas from a boiler fired by bituminous coal. UCARSOL FGC 3000 is an advanced amine solvent developed by Dow for flue gas applications.

The pilot plant has a CO₂ removal capacity of approximately 1800 tonnes of CO₂ per year and can capture more than 90 per cent of CO₂ at the inlet.

Commissioning began in August 2009 and inauguration was in September of that year. The following test programme covered a wide range of operating conditions under steady states and transient states. It began to provide information on solvent performance, including amine stability and degradation with continuous operational stability.

A state-of-the-art laboratory at the plant measures solvent composition, CO₂ loadings, solvent contamination and degradation species. Solvent composition is controlled by flue gas pre-treatment and solvent reclamation.

The initial feedback is very encouraging and should be developed in the coming months, when more extensive data will be consolidated over a sufficiently long test period. These results are now being used to develop large-scale demonstration plants of above 250 MWe under the EU Flagship programme in Europe and the DOE Industrial Program in the US.

Click to view Figure 5: Illustration of the CO₂ validation pilot to be constructed at the Statoilhydro Mongstad refinery

3.2.1 Main Field Pilot Testing Results at We Energies

Figure 6 shows the CO₂ capture field pilot at the We Energies Pleasant Prairie power plant (P4) in Wisconsin, which has been successfully installed and tested.
P4 was retrofitted with new wet FGD systems for the control of sulphur dioxide (SO₂) emissions. This included the construction of a new chimney, which can be seen in the right of the picture. The pilot system is installed on Unit 2 and located next to the new chimney. Figure 7 shows the constructed pilot system.

Additional objectives of the project included:

- CO₂ removal efficiency of 90 per cent
- Low ammonia slip from DCC2 overhead
- High CO₂ quality with low ammonia slip and low moisture content
- Low system pressure drop

Additional objectives of the project included:

- Demonstration of operation of the full system on actual flue gas, including but not limited to flue gas cooling using heat recovery/exchange and chilling, removal of residual pollutants, CO₂ absorption and regeneration
- Start of the identification of operational issues with operation, start-up and shutdown and the beginning of the establishment of system reliability
- Collection of empirical data for the key technical parameters that drive energy consumption – for example heat of reaction and heat of vaporization – compared with original Alstom estimates to validate the process energy consumption and compare it with other technologies

The status of the project is as follows, construction began in July 2007 and commissioning in April 2008. Following a planned outage of the power plant, operations and testing began in June 2008. The pilot has logged over 7000 operating hours and, since September 2008, has reliably operated 24 hours per day, seven days per week. There have been eight outages:

- Two forced outages of the power plant that were unrelated to the field pilot
- One planned outage to provide the pilot operations and validation teams a break over the Christmas and New Year holiday
- Three planned outages to support additional modifications to the pilot plant
- Two forced outages to perform maintenance on the mechanical chiller and inspect and troubleshoot a malfunctioning electric heater for the ammonia stripper

The We Energies plant was a first-of-a-kind pilot designed for continuous operation. The experience in operating the field pilot has been invaluable as the Alstom operations and validation teams have developed and refined start-up and shutdown procedures. During the initial months of operation the validation team identified a number of issues that required design modifications. As these modifications were implemented, pilot performance steadily improved to the point that stable absorber operation at 100 per cent of design flue gas flow was established in April 2009. From this point, the pilot has demonstrated the ability to meet the key performance objectives defined earlier.

Since January 2009, parametric testing has been performed on the various pilot sub-systems, including the ammonia stripper, the CO₂ regenerator, the water-wash column and the CO₂ absorber column. As parametric testing is performed, operating parameters are intentionally adjusted to generate empirical data that can be used to predict performance as a function of these parameters. While this testing provides a deeper understanding of the process, the unit does not always operate in optimized conditions. This must be considered while reviewing the operating data that are presented below.

Alstom performed additional parametric tests in August 2009 and then a final long-term test to provide empirical data, operating in steady-state conditions at the optimal set of parameters identified during the parametric testing phase. The test programme at the P4 pilot was completed in October 2009, concluding successfully the validation campaign. We now summarize some of the main results.

### 3.2.1.1 Rate of CO₂ Absorption and Regeneration

The design flue gas flow rate of the P4 pilot is 4700 SCFM. As
Figure 8 illustrates, the CO₂ capture efficiency has generally been 80–95 per cent with an average removal efficiency of 88.6 per cent across the entire period. Design conditions for the flue gas flow rate were achieved in April 2009. Some of the variability in capture efficiency is due to ongoing parametric testing in which operating parameters are intentionally adjusted. The gaps in the data represent periods during which the field pilot was out of service.

**CLICK TO VIEW FIGURE 8:** MEASURED CAPTURE EFFICIENCY ACROSS THE CO₂ ABSORBER AT P4

### 3.2.1.2 CO₂ PURITY

The CO₂ purity has been consistently high. Figure 9 provides data collected from the FTIR system from May to July 2009. The moisture content in the stream has consistently been measured as 2000–4000 ppm. The process operations have been stabilized. Figure 9 illustrates that the average concentration of the ammonia has been reduced to less than 10 ppm.

**CLICK TO VIEW FIGURE 9:** MEASURED CO₂ PURITY AND AMMONIA SLIP FROM THE CO₂ REGENERATOR AT P4. AVERAGE MOISTURE CONCENTRATIONS HAVE BEEN MEASURED AT AROUND 2500 PPM.

#### 3.2.1.3 AMMONIA SLIP FROM DCC2

Figure 10 provides ammonia slip measurements from the FTIR system. The ammonia slip from the process in earlier months had been higher than expected, mainly because of:

- Modifications to the ammonia stripper that significantly improved the water quality used in the water-wash column. These modifications are now part of the standard design.
- Improved performance of the water-wash column, reducing ammonia concentrations in DCC2.
- Improved process control of DCC2 and better control of the pH in the DCC water loop. This reduced ammonia emissions to the atmosphere.

**CLICK TO VIEW FIGURE 10:** MEASURED AMMONIA SLIP FROM THE P4 PILOT AT WE ENERGIES 5 MW CHILLED AMMONIA PILOT PLANT, MEASURED AT THE OUTLET OF THE DCC2 COLUMN. DATA WAS COLLECTED FROM THE PILOT PROCESS CONTROL SYSTEM AND COMPARED WITH GAS SAMPLES TAKEN AT THE SAMPLING PORT OF THE DCC2 OUTLET USING DRAGGER TUBES AND STACK IMPINGERS.

As the performance of these systems improved, further troubleshooting with support from the FTIR vendor resulted in the discovery of accumulated ammonium carbonate/bicarbonate solids in the sampling ports. These contaminated the samples collected by the FTIR. Alstom and the vendor implemented some simple design modifications and revised our maintenance plan to ensure that the ports remain clean in the future.

These actions have reduced the ammonia slip generally measured by the FTIR device to less than 40 ppm. However, Alstom has taken measurements using dragger tubes, shown in Figure 10. The slip passing through the FTIR sampling sequencer is measured at 10–25 ppm but is only 0–2 ppm when measured at the sample port at the DCC2 overhead. Furthermore, the EPRI has conducted several gas-sampling campaigns in which it has used impingers to measure ammonia slip.

The results of the campaigns conducted from May to June 2009 are also illustrated in Figure 10. These sampling campaigns have yielded results that are consistent with Alstom’s dragger tube measurements at the DCC2 overhead.

Alstom has concluded that the ammonia slip from the pilot is generally being maintained below 10 ppm and is normally less than 5 ppm when measured at the sample port at the outlet of the process. Alstom continues to work with the FTIR vendor to resolve the remaining discrepancies and is considering the retrofit of a dedicated instrument that is specifically designed to measure low concentrations of ammonia.

Alstom will be performing additional parametric tests in August and will then perform a long-term test that is expected to provide empirical data, operating in steady-state conditions at the optimal set of parameters identified during the parametric testing phase. Testing at the P4 pilot is scheduled to conclude before the end of 2009.

### 3.3 OXY-COMBUSTION IN SMALL AND MEDIUM-SCALE PILOTS

Alstom is involved in three pilots concerning oxy-combustion, all of which have begun operating:

- Schwartz Pumpe, Vattenfall’s 30 MWth lignite pilot plant in Brandenburg, Germany. We will provide more detail below about this medium-scale pilot plant, which was the first CO₂ capture project of its size and was installed and started up in August 2008.
- A 30 MWth oxy-firing demonstration project developed by Total in Lacq, France, for which Alstom has retrofitted an existing boiler with natural gas oxy-combustion. The pilot started operation under oxy-combustion conditions in July 2009 and will be tested over two years. It is the first integrated capture, transport and storage unit in Europe. The captured CO₂ is transported in a 30-km long pipe and stored in a depleted gas field in the Lacq region.
- A 1.5 MWth oxy-combustion boiler simulation facility at the Alstom Power Plant Laboratory (PPL) in Windsor, Connecticut.
USA. This is testing several bituminous coals and lignite in various configurations of oxy-combustion, for example a burner in a tangential firing system.

3.3.1 VATTENFALL’S SCHWARZE PUMPE PILOT PLANT
Alstom supplied the oxy-combustion steam generator and the electrostatic precipitator and further ancillary systems for the oxy-combustion pilot plant. In addition Alstom, as Vattenfall’s technology partner, is participating in a comprehensive test programme. The special feature of the pilot plant is the testing of the entire oxy-combustion technology chain, in other words, air separation unit, steam generator including indirect firing system, flue gas cleaning components and CO₂ plant.

The separated CO₂ is liquefied at the end of the process chain, with a purity of greater than 99.7 per cent, and is provided for the independent supply of various storage projects and industrial customers. The pilot plant’s construction started in October 2007. It began operation in September 2008. Figure 11 shows an aerial view of the oxy-combustion pilot plant at Schwarze Pumpe.

CLICK TO VIEW FIGURE 11: AERIAL VIEW OF THE OXY-COMBUSTION PILOT PLANT IN SCHWARZE PUMPE

The feasibility of the technology has already been demonstrated on a pilot plant scale with the commissioning of the complete technology chain and the capture of CO₂ in September 2008. Since December 2008 the plant has been in test operation. As of February 2010 it reached a total of 5000 operating hours, of which 2000 hours are in air mode and 3000 hours in oxy-combustion mode.

The steam generator and the firing system are designed to allow for best operational flexibility, in other words, a 100 per cent load can be operated both under air and at oxy-firing conditions. In oxy-firing operation the oxygen necessary for the combustion is supplied by an air separation unit. Several options are available for the inter-mixing of oxygen.

Besides the pre-mixing of oxygen and flue gas at a central location, the burner allows for oxygen-enriching of each of the oxidant flows individually (burner compartments and oxidant staging ports). The secondary flue gas recirculation is extracted downstream of the electrostatic precipitator. In addition, a smaller amount of flue gas is extracted downstream of the flue gas condenser (dry flue gas recycle) and used for fuel conveyance. The flue gas produced leaves the combustion chamber and passes an electrostatic precipitator for removal of ash particles. Before being dried and entering the CO₂ processing plant, the flue gas passes the desulphurization unit.

We now present results from the operation of the steam generator with dry lignite from the Lusatian region.

3.3.1.1 AIR IN-LEAKAGE
Any air in-leakage in the overall system should be prevented as far as is possible in order to avoid any additional increase in the energy expenditure during the downstream CO₂ purification and compression phase.

On the basis of the I&C system data and with the flue gas composition measurements up and downstream of the electrostatic precipitator, the total air in-leakage during oxy-combustion operation could be globally maintained below 2 per cent for the steam generator and electrostatic precipitator.

It was further observed that two-thirds of these in-leakages occur in the steam generator whereas onethird are via the electrostatic precipitator. Because of the integration of a special seal and cooling gas system that uses recycled flue gas, the parameters were clearly below the specified values.

3.3.1.2 CONTROL CHARACTERISTIC AND LIVE STEAM TEMPERATURES
Regarding the behaviour of the steam generator, the parameters, already obtained during commissioning, have met expectations. The live steam parameters (25 bar and 350 °C) have been proven across a load range of 50–100 per cent, both in air and oxy-combustion modes. Thanks to process balancing, temperature measurements and controls, a furnace exit temperature of less than 1000 °C was maintained.

3.3.1.3 UNBURNT MATTER AND FILTER ASH
The analytical results of ash samples collected in the boiler hopper and electrostatic precipitator in air and oxy-combustion mode show typical good burnout values for lignite, with total organic carbon (TOC) content maintained below 5 per cent by weight.

3.3.1.4 DYNAMIC PROCESSES
The connection of the other key components of the oxy-chain to the steam generator – including the air separation unit (ASU), air quality control system (AQCS), condenser and gas processing unit (or CO₂ plant) – was successful and went smoothly. Only minor adjustments of the planned control structure had to be made.

To learn as much as possible to help in the operation of future large-scale plants, all standard procedures such as venting, start-up, shutdown and load changes were automated. This allowed us to achieve the same degree of automation as in a commercial plant.

So all control loops have been adjusted to fulfill both air and oxy-combustion mode requirements. Minor adaptations were made during the commissioning phase but all relevant control loops have been successfully started-up, in other words, all standard procedures are covered via control loops and step sequences.

Typical durations for standard procedures are:
• About 20 minutes for the venting of the boiler and flue gas paths
• About 45 minutes for start of fire-up to full load, in which the boiler was preheated according to operating instructions;
• 20–30 minutes for load transfer, air to oxy-combustion mode

As expected the optimization work showed that the firing system reacts slower in the oxy-combustion mode than in the air mode. In other words, the flue gas concentrations change more slowly because of the flue gas recirculation.

After a parameter modification, steady-state conditions were achieved again in 30–45 minutes. Figure 12 shows the transition from air to oxy-combustion mode. The oxidant flow is the oxygen carrying flow. This comprises either air, recirculated flue gas and mixed-in oxygen from the ASU, or, in the transition state, a mixture of the above gas flows. For the switchover procedure, it takes about 20 minutes from the start of the closure of the intake air damper to the complete opening of the flue gas recycle damper.

3.3.1.5 EMISSION VALUES AND CO2 CONCENTRATION

Both the air and oxy-combustion modes met the emission limit values of the Technical Instructions on Air Quality Control (TA Luft).

The dust concentration determined in air mode downstream of the electrostatic precipitator is safely below the emission limit value of TA Luft. The specified SO2 emission limit is met at part load operation and in air mode alone by the SO2 separation in the FGD system. At a load of above 75 per cent the desulfurization is supported by the addition of hydrated lime into the furnace. Correct distribution of the combustion air between burner and the overfire air levels (staged combustion) kept the NOx and CO concentrations in air mode and in part load operation at the same level as in full load. Values reached are, respectively, under 300 mg/Nm³ and under 100 mg/Nm³.

The oxy-combustion operation has shown that an unstaged oxidant operation is sufficient to meet the NOx emission value. The reason for this is the significantly reduced amount of thermally formed NOx because of the missing atmospheric nitrogen in oxy-combustion mode. The CO2 concentration measured in the flue gas downstream of the electrostatic precipitator is above 85 per cent by volume, dry.

The above-mentioned data were gathered in the so-called pre-mixed mode of operation. In this mode the O2 concentration is identical in all burner registers and the admixture of the oxygen from the ASU to the recirculated flue gas is performed before the distribution of the oxidant flows among the burner and OFA cross sections.

CLICK TO VIEW FIGURE 13: SWITCHOVER PROCEDURE, AIR TO OXY-COMBUSTION (VOLUME FLOWS)

• This is now a front-end engineering design (FEED) contract in which negotiations are ongoing for an EPC contract. A memorandum of understanding was signed with PGE Elektrownia Belchatow for a facility to capture 1.8 million tonnes of CO2 a year through AEP to be in operation at the end of 2014/early 2015 at the Belchatow power plant in Poland. This project was selected to receive funding from the European Energy Programme for Recovery. FEED is being carried out and, the next phase, the EPC contract is scheduled for a few months’ time

• A feasibility study for Archer Daniels Midland to investigate the potential of AAP at its Decatur cogeneration plant. This project was selected for funding support by the US Department of Energy in October 2009

3.4 PRE-COMMERCIAL OR LARGE-SCALE DEMONSTRATION PHASE

The next ambitious phase of demonstration projects is expected one. All stakeholders, including power utilities, government organizations and suppliers, will put tremendous efforts into it so that these types of project can begin in the next two years and be commissioned by 2015.

This phase is based on intermediate size utility power plants, typically 100–350 MW gross, and allows the validation – at the size needed before commercial release – of the CO2 capture systems, their full integration and anticipated performances. It enables the optimization of the interfaces between systems and overall operability.

Alstom is developing different projects for post-amine, post-chilled ammonia and oxy-combustion technologies:

3.4.1 FOR THE ADVANCED AMINE PROCESS (AAP)

• A CO2 capture system designed to capture 1.5 million tonnes per year that should follow the first project with AEP on CAP. This project has been selected to receive Clean Coal Power Initiatives Round III funding made available through the American Recovery and Reinvestment Act, enacted in 2009

• An agreement was signed with TransAlta to develop a
largescale CCS scheme to retrofit a coal fired generating station west of Edmonton, Canada, based on CAP technology. This project is undergoing a FEED study. It will be installed on the Keephill 3 unit, now under construction, and was granted funding of CA$779 million ($748 million) by the Alberta CCS Fund and the Canada Clean Energy Fund and ecoENERGY Technology Initiative.

3.4.3 FOR OXY-COMBUSTION

- A feasibility study for Vattenfall to build a new 250 MW oxy-combustion boiler at Jänschwalde power plant in Germany and retrofit another existing unit with post-capture with chilled ammonia. This project was selected to receive funding from the European Energy Programme for Recovery. This step will represent the first tests of the technology in commercial conditions that are close to normal. It will confirm the technical and economic parameters of the future commercial offering.

These projects are in one or both of the evaluation and engineering phases. The first projects are expected to start the EPC phase in 2010, opening the door to several others that will allow validation of all CCS technologies under development.

4. CONCLUSION

CCS is unavoidable in the power sector if the sector is to achieve its CO₂ reduction target. Every effort should be made by governments worldwide to ensure that long-term policies and market regulations are put in place early enough. This will allow equipment suppliers to plan necessary production capacities and end-users to plan how to adapt their plant fleets.

Several technologies are being developed, including post-combustion, oxy-combustion and pre-combustion. Post and oxy-combustion will be available commercially in 2015 for large-scale plants of, for example, 800 MW. Second generation technologies are also under study for the more distant future.

Alstom’s development programme continues on schedule with medium-scale validation pilots already in operation and under test. Initial data from the chilled ammonia field pilot at We Energies’ P4 plant and from the oxy pilot in Schwartze Pumpe are very encouraging and support the idea that these technologies are commercially viable. Alstom expects similar success in the coming months in the initial results from pilots of the advanced amine process that it is developing with Dow Chemical.

The promising results from various pilots accompanying the ambitious programmes for the development of post and oxy-combustion CO₂ technologies are progressively closing gaps.

Commercialization of these products is expected from 2015. An important last step remains – the development of a large-scale demonstration unit for each technology.

Alstom is totally engaged in this challenge and is putting all its energy into completing its development roadmap and meeting the 2015 objective.

Alstom and Schlumberger will put forward an integrated CCS-ready offer. Key elements in the development of an optimized capture-ready solution that will be part of this offer is the information that Alstom has learned from the pilots and the expertise of its Plant Integrator approach.

We believe that efforts are necessary in all of these directions to contribute adequately to the expected challenging deployment of CCS to help meet fossil-fuelled power plants’ CO₂ emission reduction targets, which are mandatory when it comes to the mitigation of climate change.
Enel’s Fusina Zero Emission Combined-cycle: Experiencing Hydrogen Combustion

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ABSTRACT
With the attention paid to environmental problems rising, Enel, Europe’s second biggest electricity utility in terms of installed capacity, is strongly committed to the development and demonstration of carbon capture and storage (CCS) technologies. Enel intends to consolidate its leading position in the energy market and at the same time to combat climate change by supporting sustainable development.

The political and industrial commitment exists in Venice, Italy, for research on the use of hydrogen for power generation. This presented an opportunity to investigate the feasibility of a hydrogen-fuelled combined-cycle plant suitable for use in integrated gasification combined-cycle (IGCC) with CCS. Enel installed at Fusina near Venice a gas turbine that can burn pure hydrogen. It also installed a condensing heat recovery steam generator (HRSG) for maximum energy recovery from the turbine.

The aim was to develop reliable and cost-competitive technologies for CCS. The 16 MWe combined-cycle plant is integrated into an existing coal fired power plant. At the same time, Enel launched research activity into the development of a more environmentally friendly combustion system for the Fusina gas turbine. GE Oil & Gas – Nuovo Pignone procured the original GE10 gas turbine and with Enel coordinated the combustor development. The technology developed for the pure hydrogen turbine at Fusina and the experience gained from its operation will be useful in the design of gas turbines for advanced zero emission plants that would use hydrogen produced from coal gasification or from renewable or nuclear sources.

This paper aims to describe the first operational experience of the Fusina turbine. It also aims to illustrate the main results of the research programme, which is still ongoing, into the development of an innovative low-NOx combustor that is suitable for use with pure hydrogen fuel. In particular this article presents the experimental results of the development of a combustor that can reach a target for nitrogen oxides (NOx) emissions of 200 mg/Nm3 at 15 per cent O2.

INTRODUCTION
The increasing use of fossil fuels is contributing to a change in the composition of the atmosphere, which is causing severe climate change. The international community is asking for strong efforts to be made to reduce greenhouse gas emissions, especially those of carbon dioxide (CO2).

The control of CO2 emissions has an important role in setting environmental strategies and is one of the main objectives of Enel’s research.

Besides the increasing use of renewable energy sources and the introduction of the best available technologies for coal fired power plants, Enel considers the development of CCS technologies a fundamental target for reducing the emissions of CO2, the greenhouse gas of major concern. So Enel has launched several projects based on the development of innovative technologies for the reduction of carbon emissions. Some initiatives of note include the realization by 2015 of the first demonstration plant for the capture and storage of CO2, and the realization of the first hydrogen-fuelled combined-cycle plant in the world, in Fusina, Italy. The last initiative is Enel’s main project that relates to IGCC technology.

Over the past decade the idea of coal as an energy source for the future has gained renewed interest because of the fuel’s proven stability in supply and cost. It is therefore likely that coal will remain in an important position in the energy mix in the foreseeable future.

Interest in IGCC with CCS covers the role that the hydrogen produced in this process could play as an energy carrier. The burning of hydrogen produces no CO2 emissions. The main combustion by-product is water vapour. The creation of a hydrogen economy could make this clean energy carrier available for other uses, such as transport and stationary generation in urban areas in order to generate electricity and heat on a small scale in an ecologically sound way, or for energy storage.
HYDROGEN’S ROLE IN THE FUTURE ENERGY SCENARIO

Hydrogen produced from renewable or conventional energy sources will likely play a key role in the mid-term energy scenario because it is an energy carrier that can be used in several sectors of the economy.

In the most probable scenario, both centralized and distributed systems will be used for hydrogen production. Centralized systems that burn hydrogen produced from fossil or renewable sources will feature large plants, which allow high conversion efficiencies compared with distributed plants. This hydrogen can be burned directly in gas turbines or transported to cities for use in distributed generation systems, and as fuel for vehicles that employ fuel cells. Moreover, centralized systems offer the chance to confine the points of emissions and to apply carbon sequestration technologies there. However, hydrogen has its drawbacks.

These are related to the transportation and storage of this high-volume fuel and the embrittlement it causes in materials. These disadvantages have to be taken into consideration to evaluate the viability of long hydrogen pipelines.

In distributed systems, hydrogen would be produced mainly by electrolytic or photolytic processes. Alternatively, small-scale hydrogen stations.

- Conversion systems used to produce electricity from hydrogen differ significantly depending on size. Small applications of up to hundreds of kW typically employ fuel cells for stationary and automotive engines. The long lives and ease of maintenance of microturbines could mean they will play an important role in the local production of heat and electricity. The main issues here relate to the control of NOx emissions and the improvement of cycle efficiency.

- In large electricity plants, gasification today seems to be the most mature technology to use. Gasification of biomass and coal is a practical way to speed up the penetration of biomass as a primary fuel in hydrogen production [5].

- The biomass resources used for biomass gasification consume CO₂ in the atmosphere as part of their natural growth process, which means that biomass gasification results in a near-zero net release of greenhouse gases.

- Unlike biomass gasification in small gasifiers, cogasification mainly relates to large IGCC power plants in which a dedicated Rankine bottom cycle uses steam produced by an HRSG.

- Alternatively, cogasification can be designed to be integrated into an existing power plant boiler provided that steam is produced at the proper pressure and temperature. In this case, the realization of a dedicated bottom cycle can be avoided and the steam produced can be used to decrease the fuel consumption of the coal plant or, alternatively, to increase its power.

- The integration of an HRSG with an existing coal-fired power plant is the basis of the Fusina project that this paper describes.

THE FUSINA PROJECT

The aim of the Fusina project is to develop and demonstrate at the industrial scale the technology for the production of electricity in a zero-emission, high-efficiency power plant fuelled by hydrogen.

For this reason, a demonstration full-scale combined-cycle experimental research station has been installed in Fusina at an existing coal-fired power plant. The cycle includes a medium-sized hydrogen-fed gas turbine and a condensing HRSG and is strongly integrated with the coal plant. The steam produced in the HRSG is used to generate additional power or, if operated at a constant power, to reduce coal consumption and therefore CO₂ emissions. This means the configuration of the cycle is a hybrid cycle that produces electricity from both coal and hydrogen, providing a combined advantage in terms of carbon emissions.

Through the Fusina project, Enel aims to lead in the research and development of innovative systems for producing electricity using hydrogen as a fuel. The main targets of the project are:

- To increase knowledge and evaluate the availability and performance of hydrogen-fuelled gas turbines
- To acquire know-how on hydrogen and hydrogen/natural gas combustion and emission control technologies in gas cycles
- To investigate through long-duration tests the effect of fuel composition and steam injection on turbine blades
- To start acquiring know-how about all other aspects concerning hydrogen as a possible future energy carrier, including the safety aspects of handling and transporting the fuel
- To evaluate the opportunity in the medium-term to extract hydrogen from coal with a simultaneous production of electricity through IGCC systems with CCS

In the medium-term, coal gasification is in fact a promising technology for the production of hydrogen in large power plants in which CO₂ is captured and stored and the hydrogen used in high-efficiency combined-cycles. Enel is involved in European projects in which the gasification part of the cycle is under study, although no construction is foreseen in the short-term.

In one project, Enel is investigating geological storage of CO₂. This project relates to post-combustion and foresees the underground storage by 2015 of 1 million tonnes/year of CO₂ captured from the exhaust of a large coal plant [1]. As an electricity utility with significant experience in the construction and operation of natural gas combined-cycles, Enel decided to focus its attention on this part of the cycle.

The hydrogen needed to feed the gas turbine has to be carried by a pipeline from a chemical plant operating near the site of power production. The positions of the facilities are shown in Figure 1.
The water and most of steam are sent to Unit 4 of the coal-fired plant, thus contributing to an increase in the thermal efficiency of the plant. Part of the steam is also used in the gas turbine combustion chamber for NOx reduction.

The power plant connects via high-voltage cable to the 132 kV line system inside a switchyard, owned by the Italian National Grid Authority, close to the power plant.

The hydrogen is provided by means of a new pipeline that connects the petrochemicals area with the plant, as Figure 1 shows. The hydrogen pipeline, approximately 2.5 km long, was designed according to proposed Italian rules that are as yet in draft form. One of the most critical tasks was compliance with all the authorities involved in the granting of permits. The organizations included the Port Authority, the Fire Department, the Municipality of Venice and several health authorities.

A dedicated procedure for running and stopping the pipeline was prepared with special attention going into the case of an emergency stop. A nitrogen feeding system is installed close to the gas turbine to flux the pipelines by displacing the hydrogen if needed. The hydrogen would be discharged to the atmosphere using a dedicated torch and vent. The pipeline is divided into sections using emergency stop valves that would allow only minimal dispersion of the gas in the event of an accident.

Figure 2 shows the relative position of the main components of the plant and the pipe rack carrying the final part of the hydrogen pipeline and the steam pipe from the HRSG to the coal plant.

A simplified scheme of the integration with Unit 4 is shown in Figure 3. The values shown refer to the case of the fixed electric power generated by Unit 4. Here coal consumption is being reduced thanks to the heat extracted from the gas turbine exhaust. Unit 4’s gross thermal cycle efficiency increases from 45.25 per cent to 45.85 per cent. The 320 MW unit gross thermal cycle efficiency values reported in the scheme are determined by taking the ratio of the electrical power produced – measured at the output terminals of the main generator – to the thermal power absorbed by the fluid in the boiler. References [2] and [3] have more details.

Thanks to the integration with the existing Unit 4 of the coal-fired power plant, rated at 320 MWe, the plant operates in a high-efficiency combined-cycle. In the HRSG about 5.8 kg/s of superheated steam at 31 bar and 78 kg/s of heated water are produced using the residual energy of the exhaust gases coming from the gas turbine.
from the turbine. The hydrogen cycle will be able to produce up to 1.6 MW of electric power, which includes 4 MW produced by the existing power station thanks to this steam, with a total gross thermal efficiency of about 42 per cent.

When operating the coal plant at fixed load, the coal consumption can be reduced by 1.43 tonnes/hour, thus obtaining a reduction in CO2 emissions of about 3.4 tonnes/hour.

Table 1 summarizes the predicted base performance of the plant.

CLICK TO VIEW TABLE 1:
GE10 NOMINAL PERFORMANCE WITH HYDROGEN AS THE FUEL

PLANT ERECTION AND STARTUP

Plant construction started in December 2007 and was completed in the first half of 2009. All the activities related to plant construction and erection, such as detailed engineering activities, procurement, supplies follow up and surveillance, and erection on-site have been carried out by the Plant Development and Construction Department of Enel Engineering and Innovation. Figure 4 shows a picture taken during the construction phase.

CLICK TO VIEW FIGURE 4:
PLANT VIEW DURING CONSTRUCTION

During the commissioning phase, which started in May 2009 and ended within the year, the following goals were reached:

- First connection to the grid in May
- Maximum load with natural gas in June
- First firing with mixtures of hydrogen and natural gas in July
- Maximum load with mixtures of hydrogen and natural gas in September, with a hydrogen content of up to 75 per cent in terms of thermal input

Tests with pure hydrogen at part load have also been performed.

ON-ENGINE TEST RESULTS

The first operational experience from the Fusina power plant has demonstrated the feasibility of the safe use of hydrogen in a gas turbine equipped with a diffusive combustor. During commissioning, tests with increasing amounts of hydrogen, both with and without steam injection, have been performed under the supervision of the turbine manufacturer.

On-engine tests mainly focused on assessing the levels of NOx emissions from the gas turbine. An inline emission analyzer is installed on each of the two stacks. Due to the limited availability of hydrogen, tests with pure hydrogen were limited to 35 per cent of baseline. In this range, we observed that the ratio of emissions with hydrogen to emissions with natural gas was about three, as Figure 5 shows. This met expectations from previous experimental tests. Tests were carried out with ambient temperature higher than ISO conditions, so the maximum electric power provided by the engine operating at full speed, full load (FSFL) was 90 per cent of the ISO maximum performance.

CLICK TO VIEW FIGURE 5:
NOX EMISSIONS IN DRY OPERATIONS

At maximum load the hydrogen fraction in the fuel was increased to about 75 per cent in terms of thermal input, in other words, about 90 per cent by volume, as Figure 6 shows.

Maximum load operation was possible with mixtures of hydrogen and natural gas that contained a hydrogen volume fraction of up to about 90 per cent.

CLICK TO VIEW FIGURE 6:
NOX EMISSIONS, DRY AT FSFL

The NOx reduction was performed by means of steam injection. The effect of the steam on NOx emissions when operating at maximum load is shown in Figure 7. This test has been performed with a 55 per cent thermal input from hydrogen, since this corresponds to the maximum flow of hydrogen that could be steadily maintained.

CLICK TO VIEW FIGURE 7:
EFFECT OF STEAM INJECTION ON NOX EMISSIONS AT FSFL, WITH A 55 PER CENT THERMAL INPUT FROM HYDROGEN

The steam flow has been increased up to a value higher than two of the ratio between the steam and the methane that provides the same thermal input of the fuel mixture. Even though the machine has proved to be able to operate with this very large amount of steam without problems, this value is over the maximum allowed for continuous operation because the increased heat exchange in the turbine could reduce the life of its components.

Based on both on-engine results and previous experience from the Sesta test rig, in pure hydrogen operation a steam-fuel ratio slightly over one will be required to comply with the emissions limit for the first phase: 400 mg/Nm³ at 15 per cent O2, equivalent to 195 ppm at 15 per cent O2.

LOW-NOX COMBUSTOR DEVELOPMENT

As mentioned previously the first operational experience from Fusina showed the feasibility of the safe use of hydrogen in a gas turbine equipped with a diffusive combustor.

Moreover the experience confirmed that in the case of operation with hydrogen, NOx emissions are about three times higher...
than those produced with natural gas. This is because the flame temperature of hydrogen is roughly 150 °C higher than that of natural gas.

In the case of a diffusive combustor, significant mitigation of NOx emissions can be obtained by injecting steam into the combustion chamber. The main drawbacks of using a large quantity of steam are the penalty in terms of cycle efficiency and the increased heat transfer rate in the turbine blades.

A research programme was launched for development of the combustor. This involved both experimental and modeling activities, and its aim was to minimize the environmental impact of the hydrogen plant without reducing the efficiency of the cycle.

Besides Enel and GE Oil & Gas – Nuovo Pignone, the research programme involved research departments of the main Italian universities. Financial support came from Regione Veneto, a local institution in the northeast of Italy, and the Italian Ministry of the Environment (MATT). The development activity involved three steps:

- First phase: selection of the combustor for installation in the Fusina gas turbine
  NOx < 400 mg/Nm³ at 15 per cent O₂
- Second phase: minor modifications to the GE combustor
  NOx < 200 mg/Nm³ at 15 per cent O₂
- Third phase: advanced combustor
  NOx < 100 mg/Nm³ at 15 per cent O₂

Results from experiments [4] performed in Enel’s Sesta test rig in Tuscany were behind the choice of the combustor hardware for the Fusina power plant in the first development step.

A schematic view of the combustion chamber currently installed at the Fusina gas turbine is shown in Figure 8.

CLICK TO VIEW FIGURE 8: COMBUSTOR INSTALLED ON THE FUSINA GE10 GT

Air from the compressor discharge plenum is directed to the combustor head through the annular section, which comprises the external casing and the liner (reverse flow configuration). Air is injected into the combustion zone through dilution holes, cooling holes (grouped in several rows and located along the entire length of the combustor) and primary combustion holes. Cooling of the liner is by means of both impingement and film cooling techniques and involves a significant fraction of the total amount of air for combustion.

The diffusive burner is at the top of the combustor. It consists of a simple multi-hole fuel nozzle. The burner tip consists of an axial air swirler that takes a small amount of combustion air. Fuel injection occurs within swirler slots, with no or negligible air-fuel premixing within the slots. The GE10 gas turbine configuration is such that the combustor axis is perpendicular to the engine axis. The direction of hot gases exiting the circular section of the combustor turns. They are distributed to the annular section of the turbine’s first-stage statoric nozzle by means of a complex component called a transition piece. Steam can be injected both directly into the cold-side combustion air stream through the external combustor head (cap) and through the burner nozzle whose use was originally to handle a secondary fuel.

In the second phase of the development of the combustor, an experimental campaign was carried out in the Sesta test rig to select combustor hardware that can achieve a NOx emissions target of 200 mg/Nm³ at 15 per cent O₂.

The Sesta test rig is suitable for full-scale, full-pressure testing of a wide variety of combustion systems. Compressed air is supplied by a train of two compressors driven by a 30 MW-plus electric motor. The maximum air flow capability is about 40 kg/s. About 20 per cent of the compressed air has to be used to cool the rig and test hardware components.

Variable combustion air temperatures are achievable by means of electric heaters of overall power of about 8 MW. A flexible multi-fuel supply system uses multiple feed lines to allow the production of fuel mixtures of different compositions and distributions for the combustion system.

B1 Burner:
- Axial swirler
- Fuel injection located inside the swirler vanes; two distinct fuel flanges supply half of the fuel nozzles each; alternation is in the circumferential direction
- Steam injection through half of the fuel holes

B2 Burner:
- Two concentric axial swirlers
- Three fuel injection rows:
  - Two rows with coflow configuration
  - One row with crossflow configuration, injection located inside the external swirler vanes

B3 Burner:
- Double swirlers; the external one has radial configuration, the internal one has axial configuration
- Two fuel injection rows with distinct delivering points; the first is inside the radial swirler vanes and the second immediately downstream of them

Several combinations of three burners (B1, B2 & B3) and three liners (L1, L2 & L3) were characterized in terms of NOx emissions, liner metal temperature, pressure fluctuations and temperature...
distribution of flue gases at the combustor exit. Liner L2 has been modified during tests. Only the last version, called L2m, is described below. Burners B1, B2 and B3 are shown in Figure 9, Figure 10 and Figure 11, respectively.

CLICK TO VIEW FIGURE 9: B1 BURNER

CLICK TO VIEW FIGURE 10: B2 BURNER

CLICK TO VIEW FIGURE 11: B3 BURNER

The features of the tested liners are shown below.

L1 Liner:
- GE liner installed on the Fusina gas turbine
- Three-hole rows for the primary air (40.9 per cent of the total flow). Here primary air refers to the air flowing through liner primary holes, burner and liner cap
- Four dilution air holes (13.5 per cent of the total flow)
- Cooling air slots along the liner surface (45.5 per cent of the total flow)

L2m Liner:
- Primary air holes: same pattern as L1 but with larger total area (65.9 per cent of the total flow)
- Two dilution air holes (9.9 per cent of the total flow)
- Cooling air slots featured by reduced air flow (24.2 per cent of the total flow)

L3 Liner:
- Primary air holes: two-hole rows, total area larger than that of L1 (60.5 per cent of the total flow)
- Two dilution air holes (5.2 per cent of the total flow)
- Cooling air slots featured by reduced air flow (34.3 per cent of the total flow)

The liner installed in the Fusina engine [L1] is shown in Figure 12.

CLICK TO VIEW FIGURE 12: L1 LINER

Due to the large number of possible burner-liner combinations, we investigated only a reduced number with hydrogen supply and steam injection. In order to select the most promising hardware configurations for characterization, a prescreening test was carried out that fed the combustion system with natural gas only. The prescreening test led to the selection of B1 Burner as the only one to be characterized in the second step of the experimental activity. The reasons for this choice are:

- B3 Burner produces slightly less NOx emissions compared with the standard burner, B1, but showed combustion instabilities at both low load in dry operation and high load in wet operation.
- B2 Burner installed on the L2 Liner caused the temperature of the liner metal to become too high. Also, combustion instabilities were observed during some load variation. B2 Burner reduced NOx emissions by about 10-15 per cent compared with the standard burner.

Table 2 shows the configurations investigated in the second phase of the experimental activity. Several thermal load conditions were characterized although only full-load results are presented here.

CLICK TO VIEW TABLE 2: COMBUSTOR CONFIGURATIONS THAT CAME UNDER INVESTIGATION

With regard to the abatement of NOx emissions, several steam injection strategies were tested. In particular, steam was injected both through the secondary fuel holes (therefore alternating fuel and steam jets inside the swirler vanes) and mixed with the combustion air entering the cap of the liner. The effect of the steam flow distribution between the burner and the cap on the abatement efficiency was also evaluated.

Figure 13 shows NOx emissions performances of the three configurations at different amounts of injected steam. To quantify the amount of injected steam the ratio of steam flow rate to natural gas flow rate was taken. For hydrogen operation, the thermal equivalent natural gas flow rate was used, indicated by \( S/F_{eq} \) in Figure 13.

CLICK TO VIEW FIGURE 13: EFFECT OF STEAM INJECTION ON ABATEMENT OF NOX EMISSIONS (100 PER CENT HYDROGEN FUEL)

Figure 13 shows that the steam injection allowed all the three configurations to achieve the NOx emissions target of 200 mg/Nm³ at 15 per cent \( O_2 \). Lower values exhibited by Configuration 2 and Configuration 3 confirm that the increase of the primary air led to a positive effect on the mitigation of NOx. Also, the abatement effectiveness decreased at higher steam flow rates.

To evaluate the applicability of the three hardware configurations to the Fusina gas turbine, metal temperatures were measured along the liner by means of several thermocouple rows. The comparison between measured values and the manufacturer threshold value.
allowed the selection of two possible configurations suitable for installation in the Fusina gas turbine. The operation with hydrogen led to a metal temperature increase of around 50 °C compared with operation with natural gas.

The gas temperature distribution at the transition piece outlet is another important parameter that determines the suitability of the combustor for installation in the gas turbine. All three configurations showed distribution values compatible with the turbine inlet requirements.

Finally, pressure fluctuations inside the combustion chamber were measured for the three configurations at several thermal loads.

With regard to the operation at low load and with natural gas supply, no significant differences were found among the three configurations. All showed low-pressure fluctuations. However, some combustion instability phenomena were observed with one configuration in the case of operation at low load in dry conditions and high load in wet conditions. Operation with hydrogen exhibited lower pressure fluctuations than that with natural gas.

CONCLUSIONS

In the short-term, the main target of the project is to assess engine performance at nominal load with a supply of pure hydrogen. The aim is to validate the results of a previous experimental campaign performed at the Sesta test rig and to acquire knowledge about hydrogen combustion at the industrial scale. Moreover we plan to perform research on materials and combustor development in the long-term.

To achieve the short-term target a detailed investigation of the effect of hydrogen and steam on the hot parts of the turbine will be carried out. Components’ integrity and degradation kinetics will be assessed by means of both overengine inspections and components analysis. The presence of hot corrosion or high-temperature oxidation will be verified after a period of operation of several thousands of hours.

With regard to combustion, important research jointly carried out by Enel and GE Oil & Gas – Nuovo Pignone is planned. Its aim is to develop a combustor able to match the NOx emissions limit of 100 mg/Nm³ at 15 per cent O₂. In addition to the evaluation of the applicability of consolidated low-NOx technologies to hydrogen combustion, the research project will investigate innovative solutions by means of both modeling and experiments under atmospheric and full-scale, full-pressure reactive conditions.

FUTURE RESEARCH PROGRAMME

In order to match the NOx emissions limit of 100 mg/Nm³ at 15 per cent O₂, Enel and GE Oil & Gas – Nuovo Pignone plan to launch a new research project that will test the application of innovative combustion technologies fuelled by hydrogen.

The innovative gas turbine combined-cycle that included a gas turbine whose fuel was pure hydrogen is one of the most advanced facilities for the study of the impact of hydrogen on both turbine combustion and materials. The results from this study will help improve both large and small gas turbine systems fed by hydrogen that is produced from coal, the biomass-coal gasification process, or solar or nuclear energy.

This paper illustrates the recent progress made in the realization and the commissioning of the plant, as well as the results of the development of a 200 mg/Nm³ at 15 per cent O₂, of NOx. The commissioning phase was carried out after the conclusion of the construction phase in the first half of 2009. Tests with pure hydrogen, natural gas and blends, in dry conditions as well as with different amounts of steam, demonstrated the feasibility of the safe use of hydrogen in a gas turbine equipped with a diffusive combustor. With steam injection, NOx emissions have been reduced to 400 mg/Nm³, as expected, and the feasibility of a further reduction by means of steam flow increase has been demonstrated.

With regards to the development of the low-NOx combustion system, jointly carried out by Enel and GE Oil & Gas – Nuovo Pignone, an experimental campaign at full pressure conditions was carried out with the aim of selecting a combustor able to guarantee NOx emissions below 200 mg/Nm³ at 15 per cent O₂ in hydrogen operation.

Among several tested configurations, we identified two that met the emissions requirement and that were suitable for installation in the Fusina gas turbine. In both configurations, a NOx abatement strategy based on steam injection in the combustion chamber was used. Further decreases in NOx emissions by means of steam injection does not seem feasible because of the high steam flow rate required.

In order to match the NOx emissions limit of 100 mg/Nm³ at 15 per cent O₂, Enel and GE Oil & Gas – Nuovo Pignone plan to launch a new research project that will test the application of innovative combustion technologies fuelled by hydrogen.
POWER-GEN EUROPE: REDUCING THE CARBON FOOTPRINT OF FOSSIL POWER GENERATION

ACKNOWLEDGEMENT

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Evaluation of the Use of Different Combinations of Solar Add-ons with Coal Fired Power Plants

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ABSTRACT
The various types of concentrating solar power (CSP) technology will play an important role in the future generation of electricity, heat and cooling. A promising way to implement this technology is the combination of CSP with existing or newly built fossil fuel fired power plants. In these hybrid plants, the solar add-on saves fuel by taking over a part of the steam supply of the conventional plant that is normally supplied by fossil fuel. It may also increase the peak load capability.

In this paper, the example of a linear Fresnel collector from the Solar Power Group is used to investigate the influence of solar add-ons that generate superheated steam on the overall performance of a regular coal fired power plant. A solar field that is supplying steam to the pre-heating stages of the power block reduces extraction of steam from the turbine. This leads either to a higher electric output of the system or to the saving of fuel if the output is kept constant. The most relevant effects are observed in the electrical efficiency and in fuel consumption.

The focus of the investigation is on the impact of the entry point on the conventional water/steam cycle and the potential of using several points of supply for solar steam. The impact of lessening bleed extractions during high direct normal irradiance (DNI) hours is simulated for a 350 MW coal fired power plant operating at selected locations in the USA and Australia.

The thermodynamic performance and potential to save fossil fuel — and thereby reduce the carbon footprint of power generation — of different combinations of solar steam management are analyzed. This paper describes and evaluates the expected economic benefits in terms of a strategic tariff system, integrating a feed-in tariff with the potential revenues from fuel savings and avoided carbon dioxide (CO₂) emissions. The generation costs and the internal rate of return (IRR) set a reference from which a project-specific adjustment of the feed-in tariff can be made.

1. OBJECTIVES
The aim of this study is to demonstrate and assess the potential fuel and cost savings that can be achieved by retrofitting a Fresnel system in an existing coal fired power plant. Fresnel collectors provide the thermal energy required by the regenerative feedwater heaters for preheating the medium. Therefore the steam taken from the extractions of the turbine is replaced by the solar system.

Concentrating solar technologies require a high level of direct solar irradiation. The solar resources in the MENA region, the southwestern USA and Australia are among the best in the world, which makes them suitable regions for this kind of application.

CSP technologies concentrate solar energy and convert it into medium to high-temperature heat. Those systems use concentrating collectors that can be divided into point-focusing systems, for example the parabolic dish and power tower, and line-focusing systems such as parabolic trough and linear Fresnel collector.

Coal fired power plants produce electricity using a steam turbine. Retrofitting existing coal fired power plants is a low-cost option for solar thermal systems, as most of the existing system can be used. Solar add-ons can be a simultaneous way to expand the use of solar energy and trim carbon footprints. The implementation of a solar system into the power plant does not affect the steam cycle or the electrical...
Rosiel Millan accepted the award on behalf of Jacques de Lalaing.
efficiency during periods of low irradiation because the fuel supply can be adjusted according to the thermal energy available from the solar system.

The integration of a CSP application into an existing power plant is best achieved with a direct steam generating system. In that way, it can be directly connected to the steam cycle and does not require additional heat transfer media and heat exchangers. A suitable solar thermal technology for this application should offer the ability not only to generate direct steam but to produce superheated steam at the temperature required by the power plant.

3. HYBRID SYSTEM

3.1 COAL FIRED POWER PLANT

A regenerative steam power cycle with a six-stage feedwater heating system (five close feedwater heaters and one open feedwater heater – FWH 3) is used as a base case (see the process flow diagram (PFD) in Figure 1). This simplified PFD represents a typical design of coal fired power plants installed in many countries such as the USA and Australia.

The chosen electricity capacity of the coal fired power plant is 350 MW. The temperature of the heat transfer fluid, steam, varies from around 50 °C to over 500 °C, giving a wide temperature range for the integration of the solar system.

3.2 SOLAR THERMAL SYSTEM USING FRESNEL TECHNOLOGY

The solar field consists of 120 collector modules. Each collector module has a mirror surface of about 1400 m² distributed in 24 rows that concentrate the light on a horizontal pipe 8 metres above, through which water or steam circulates. Each row is 96 metres long and comprises 16 mirrors. The solar collector field is divided into three sections, analogous to a regular boiler.

In the pre-heating section, the feedwater is heated to a temperature close to the evaporation point at the operating pressure and then sent to the steam drum. In the evaporation section, the feedwater coming from the steam drum is gradually evaporated. This section is designed to have a certain degree of steam wetness at its outlet, which means that part of the flow is still in liquid phase.

To ensure dry steam conditions at the entrance of the superheating section, the wet steam coming out of the evaporation section is separated out in the steam drum. The temperature of the steam is further raised in the super-heating section to the desired outlet condition.

The three sections of the solar field are shown in Figure 2.

CLICK TO VIEW FIGURE 2:

SECTIONS OF THE COLLECTOR FIELD

3.3 INTEGRATION OF THE SOLAR THERMAL SYSTEM INTO THE EXISTING COAL FIRED POWER PLANT

The solar system is integrated into the existing coal fired power plant using a six-stage feedwater heating system. It is installed in parallel with the existing high and intermediate pressure (HP/IP) feedwater heaters.

This arrangement allows high flexibility because the maximum solar energy input can be used and the low solar heat input can be compensated for independent of the required load demand.

The economical impact and the electrical efficiency of reducing HP extraction steam are much higher than for low-pressure (LP) extraction steam. For this reason, the solar system is designed to replace the bleed extractions from the steam turbine for the HP and IP feedwater heaters, FWH 1 and FWH 2 respectively.

The open feedwater (FWH 3) supplies the solar field with the required feed water. The amount of feed water that is pumped to the solar field not only depends on the feedwater heater demands, but also on the availability of solar irradiation.

The working temperature and pressure of the solar field is given by the operating conditions of FWH 1, thus the steam flow is throttled before entering into FWH 2 and FWH 3.

CLICK TO VIEW FIGURE 3:

PROCESS FLOW DIAGRAM OF THE HYBRID POWER PLANT

Regarding the distribution of the solar steam to the preheating system, two cases are proposed: one that gives priority to FWH 1 demand and another that supplies the same amount of heat to FWH 1, FWH 2 and FWH 3.

CASE A: STEAM FLOW PRIORITY TO HP FEEDWATER HEATER

The steam from the preheating section is distributed to the feedwater heaters in a given order, with FWH 1 having the highest priority.

First, the demand of FWH 1 is covered. Any surplus is fed into FWH 2. In case the steam generated by the solar field exceeds the requirement of FWH 1 and 2, FWH 3 receives the surplus steam produced. The bleed extractions from the turbine ensure that sufficient steam is provided to the feedwater heaters regardless of the output of the solar field.

CASE B: STEAM FLOW SPLIT

In this case, a steam header splits the outlet steam of the solar field into three streams with the same flow rate. The three outlet flows of the header have the same composition and specific enthalspy as the header’s inlet.
As in Case A, the bleed extractions from the turbine ensure that sufficient steam is provided to the feedwater heaters regardless of the output of the solar field.

3.4 POWER PLANT LOCATIONS
Suitable locations for CSP plants are arid and semi-arid regions in which the annual DNI is above 1700 kWh/m². The solar irradiation of the selected regions is shown in Table 1.

CLICK TO VIEW TABLE 1:
REGIONS SELECTED FOR THE STUDY

4. TECHNICAL ANALYSIS
The technical assessment comprises a comparison of the thermodynamic performances, fossil fuel saving and CO₂ emission avoidance of the two cases in the two proposed locations. Solar add-ons can either enhance the plant net output or reduce the fuel consumption. Since the base-case is an existing plant and it is uncertain how much additional steam the steam turbine and generator can handle, the target is to reduce the fuel consumption and not to increase the electricity production. The solar field is designed in such a way that its peak production does not exceed the heat demand of the HP/IP feedwater heaters at nominal load conditions of the power plant.

Power plants such as the one presented in this paper often follow daily load fluctuations from full load to the minimum turbine load. In order to simplify the control strategies and to speed up the simulations, we used a baseload plant with the turbine running at full load continuously.

Thermoflex software was used in the performance evaluation of the hybrid plant. This software allows the modelling of the various equipment of a conventional power plant and of their combination with solar components. Based on the hourly resolution of the solar and environmental data, the annual performance of solar add-ons to the coal fired power plant is assessed by calculating static loads for each hour of the year.

The number of collector modules and thereby the available mirror surface is kept constant for all simulations. The same applies for the base model of the conventional coal fired power plant. The simulations also take into account the geometry of the solar field, position of the sun, irradiation level, ambient temperature and relative humidity. The solar steam production varies according to the feedwater heater demands and solar irradiation. The electricity production of 350 MW is regulated by adjusting the coal consumption of the boiler.

CLICK TO VIEW FIGURE 4:
SHOWS THE AMOUNT OF THERMAL ENERGY GENERATED BY THE SOLAR FIELD IN THE USA AND AUSTRALIA

In Case A the heat demand of FWH 1 and FWH 2 is for some hours covered completely by the solar field. The amount of solar energy provided to FWH 1 (shown by the blue area) is higher than to FWH 2 (green area) and 3 (violet area). In Case B none of the feedwater heater demands are fully covered by the solar system. The solar field, in both locations, only provides around 70 per cent of FWH 1 demand.

CLICK TO VIEW FIGURE 5:
PERFORMANCE OF THE HYBRID POWER PLANT

Solar add-ons result in a relative plant efficiency improvement of up to 1.6 per cent in the USA and 1.5 per cent in Australia. The increment in efficiency implies lower fuel consumption and therefore higher CO₂ emission avoidance. In both regions, Case A has a higher impact on the overall performance of the plant than Case B because the HP bleed extraction from the turbine has been totally substituted by the solar system.

5. ECONOMIC ANALYSIS
Add-ons based on solar steam have an impact on generation costs, among others, because of the associated fuel savings derived from their implementation. The expected effect on the levelized electricity cost (LEC) depends on the fuel of the power plant, in other words, the cost of the equivalent fuel savings. The analysis is based on the impact of the solar field on electricity generation. Aside from fuel, generation costs include the costs of the solar collectors and their operation, whereas revenues from electricity sales are based exclusively on the corresponding solar electricity production.

The economics of solar add-ons are based on a strategy that integrates all revenues in an overall tariff, T:

\[ T = T_{\text{feed-in}} + \text{FS} + \text{CCO}_2 \]

T is the overall compensation applicable to solar add-ons, (€/kWh). \( T_{\text{feed-in}} \) is the feed-in tariff for solar thermal generation, (€/kWh). FS is the fuel savings derived from the operation of the solar field, (€/kWh). \( \text{CCO}_2 \) is the credit support due to CO₂ emission avoidance, (€/kWh).

CLICK TO VIEW TABLE 2:
ASSUMPTIONS OF THE ECONOMIC MODEL OF THE SOLAR POWERED ADD-ONS

Only the contribution of solar steam related to electricity generation generates revenues according to \( T_{\text{feed-in}} \). The electricity produced conventionally is not taken into account for revenues nor the fuel costs derived from it. The analysis shows how the Fresnel technology impacts on the generation costs and how they can be covered under the specific circumstances of the country.
economic calculation is focused on the cost of the equipment added to the plant layout and its operation. All other O&M costs of the conventional plant are independent of the analysis. This model assumes that out of the total electricity generated by the turbine, there is a fraction associated with the presence of the solar add-on. The difference in fuel consumption attained when the add-ons are operated corresponds to a certain thermal power that is indirectly put into the system by solar steam production. By means of the plant’s electrical efficiency this is related to an electricity output that is used as a reference to assess the solar field’s operation costs. The contribution of the solar field to electricity production is analogously estimated to apply the revenue system to the solar-aided power plant over 25 years. The results of the plant’s performance under the aforementioned scenarios are shown in Table 3.

CLICK TO VIEW TABLE 3:
RESULTS OF THE ECONOMIC MODEL FOR SOLAR POWERED ADD-ONS FOR EACH SITE

The higher annual DNI in the USA enables the add-ons to provide a higher thermal output because more solar hours at the site let the system achieve a higher solar share for the related electricity production. Both facts imply a higher potential for fuel savings and thus for emission avoidance.

The use of a steam flow priority header is highly recommended to allocate the thermal production of the solar field to achieve a higher reduction in fuel use and thus a more economical design. With regard to site selection exclusively, generation costs are expected to be up to €0.02/kWh ($0.03/kWh) higher in Australia. The inclusion of solar add-ons in the plant’s layout can be paid off in nine years in the USA under these circumstances, leading to a higher IRR. This is possible when the suggested tariff is composed according to Table 4.

CLICK TO VIEW TABLE 4:
BREAKDOWN OF THE SUGGESTED OVERALL TARIFF

The reference framework requires a feed-in tariff of €0.16/kWh to foster the implementation of solar add-ons with reasonable IRR, LEC and payback time. The advantages coming from fuel savings and CO₂ credits represent additional support of €0.035/kWh.

The variation in contribution of the tariff’s contributions allows the determination of how rentable the implementation of the solar add-ons will be under different scenarios that reflect, for example, variations in the price of fuel and in CO₂ credits. The range of the analysis is constrained to a 25 per cent difference in feed-in tariff and to the latest trends in coal prices. The price of carbon credits are likely to be adjusted according to the country’s regulations.

CLICK TO VIEW FIGURE 6:
VARIATION OF THE PROJECT IRR TO EQUITY

Since the sale of solar electricity has the biggest share in the proposed revenue system, the feed-in tariff is the driving force of the analysis. In the selected range, the feed-in tariff can modify the IRR by up to 2.5 per cent. Likewise it can impact the payback period by 1-2 years, depending on the site rather than on the add-ons’ configuration.

The economics of including solar add-ons in the plant layout are more sensitive to the fuel saved than to the price of carbon credits.

CLICK TO VIEW FIGURE 7:
VARIATION OF THE PAYBACK TIME

6. CONCLUSIONS

The optimum scenario for the most economic introduction of solar add-ons is, from the selected sites, the USA, because of its higher solar irradiation. Diverting the solar steam so that priority is given to the HP feedwater heater (Case A) maximizes the use of the corresponding heat input, achieving a reduction of fuel consumption that is equivalent to a rise in solar share of up to 0.2 per cent.

Using a baseload plant leads to a low solar share. For peak load plants, the solar add-ons will have a higher impact on the overall performance of the plant because their capacity factor is lower and their durations of operation are comparable to those of the solar add-ons. Therefore no potential solar production has to be wasted when the power plant is out of operation.

A feed-in tariff as low as €0.16/kWh allows implementation of the solar add-ons with a payback period of 8–10 years in the USA, depending on the system configuration. In this context the IRR remains close to 13 per cent for a coal power plant, even with volatility in the price of coal or carbon credits.

The feed-in tariff of the proposed revenue scheme is up to €0.08/kWh lower than for instance the current tariff for solar thermal in Spain (€0.26/kWh). This scheme includes the support provided by CO₂ emission avoidance and the fuel savings, a characteristic advantage of the configuration of the solar add-ons.

In the case of Australia (Case B), under no circumstances would a feed-in tariff of €0.16/kWh overcome the LEC unless CO₂ credits and a fuel saving tariff are included in the overall tariff.
POWER-GEN EUROPE

TRACK 3

GAS FIRED POWER TECHNOLOGY
Real-life Examples of Optimizing the Integration of Renewables into the European grid by Using the Fast Cycling and Grid Support Capabilities of Combined-cycle Power Plants

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ABSTRACT
Combined-cycle power plants (CCPPs) have a large share of power generation in Europe. The increasing contribution of CCPPs to power generation over the past decade can be explained by their high efficiency, short execution time and relatively low investment costs.

Regenerative and discontinuous power generation technologies like those of wind power and solar power are increasingly penetrating the market. Renewable resources are leading the way in reducing carbon dioxide (CO₂) emissions but, on the other hand, their limited availability and predictability pose a considerable challenge to grid stability.

Periods of low generation caused by weather conditions – for example low winds and overcast skies or night – have to be covered by other types of plant, such as those fired by fossil fuels. The result of this is a constant increase in the number of requirements that existing and new fossil fired power plant fleets have to meet concerning operational flexibility and rapid load response as formulated in grid codes and customer specifications. These developments are forcing the designs of modern power plants to focus strongly on operational flexibility and grid support operation in order to allow a large renewable capacity to be integrated into grid systems.

Integration of modern technologies and rigorous optimization of the plant startup process have recently enabled Siemens to build Europe’s most flexible and fastest starting CCPPs, for example in France, the Netherlands and Germany. This paper presents examples.

In the UK and similar markets the grid code’s strict requirements concerning operational behaviour when frequency deviations occur can be met by deploying a range of new technologies. Island operation and part load capability are being requested increasingly throughout developed and emerging markets. These can be provided by introducing additional and innovative plant control concepts.

Verification and validation of these capabilities has been not only through theoretical analysis but also by live testing during plant operation. This means that the benefits to the customer that result from reduced fuel consumption and CO₂ emissions during the startup and ramping process can be realized in power plants today.

This paper describes innovations in the area of plant flexibility and the results and improvements they have achieved in recently commissioned CCPPs in Europe.

1. INTRODUCTION
The CCPP is one of the more recent developments in the field of power generation fired by fossil fuel. These plants became as important as they are today in the power generating sector at the end of the 1980s. That was when power generation started to move away from the closed monopolistic market structures of the time towards today’s competition oriented markets. The CCPP’s relatively low capital costs, high plant efficiency and short construction time are the main features that make it of interest when considering new investment in a market characterized by increasingly intense competition.

The first such plants quickly superseded existing, vintage plants because of their relatively low power generating costs. Initially they were used to meet baseload requirements. Saturation of the electricity market and an increase in gas prices subsequently resulted in increased deployment of CCPPs in the intermediate load range, in other words, plants were started up and shutdown on a daily basis to cope with daytime peaks.

This new field of application first became apparent at the end of the 1990s in the US and the UK. The price of fuel continued to rise because of the large number of plants built during the boom. The regimes of base load plants that had already been planned were shifted to those of intermediate load plants.

The challenge that projects faced because of this changed requirement gave birth to the idea of trying...
to improve plant flexibility without compromising service life or efficiency.

As the market continued to develop, the demand for quicker startups soon followed the demand for more frequent startups. This market demand finally resulted in the launch of a development project called FACY (FAst CYcling) that combined all the initial engineering ideas into an integrated plant concept.

The aim of the subsequently initiated R&D programme was to design a plant that could handle an increased number of startups but with reduced startup times. The idea was to ensure, if possible, that other power plant components, such as the heat recovery steam generator (HRSG) or steam turbine, did not put limits on the gas turbine during hot and warm startups.

In the course of the project, potential areas came to light in which further optimization could be achieved, although these had to wait for a second generation of development to be implemented. The major improvement offered by this second generation involved the startup procedure.

Hold points at which a plant waits until certain steam parameters have been reached were eliminated as part of the shortened 'start on the fly' startup procedure. Here the steam turbine is started up in parallel with the gas turbine using the first steam that becomes available after a hot start.

Whereas the first FACY generation reduced startup times for a hot start from 100 minutes to 55 minutes, the second generation succeeded in driving startup times below the 40 minutes mark.

The first plants incorporating the advantages of both the first and second generations of the FACY concept are now being operated commercially. For example, startup times of 30 minutes were recorded at the 2 x 430 MW F-class singleshaft Sloe Centrale plant in the Netherlands during acceptance tests in which net efficiency was above 59 per cent. Equally good results have been exhibited by other reference plants. This means that the expectations placed on the second generation of FACY plants have been far surpassed in a number of cases.

Shortening startup times and improving starting reliability, while increasing the number of startups was only one of many requirements with respect to plant flexibility.

The ever increasing percentage of renewable resources connected to the grid results in a certain destabilization because of fluctuations in the availability of these resources. High-availability power plants such as CCPPs have to compensate for these fluctuations. For these reasons grid support requirements, which are usually defined in a grid code, have recently become more rigorous. Some of the most stringent requirements are to be found in the UK grid code. Certain subjects have presented operators with special challenges for quite some time. These are load stabilization at low frequencies, primary and secondary frequency response, and island operation.

In the recent handover of the 840 MW multishaft F-class power plant at Marchwood in the UK Siemens demonstrated that the problem could be solved by introducing technical features and optimizing the plant concept without letting maximum efficiency fall below 58 per cent.

As with the development of FACY, a decisive factor in its success was an approach that combined the potentials of several systems and components in a single solution. The challenges were met based on the use of gas turbine compressor and firing reserves and fast wet compression combined with an optimized instrumentation and control (I&C) or closed-loop control concept.

2. POWER GENERATION MARKET IN A PERIOD OF CHANGE

Figure 1 shows the actual and anticipated development of electricity production in Europe in the years 2000 to 2030. The percentage of wind and solar plants in the total installed fleet have increased from 2 per cent to 12 per cent over the past ten years.

CLICK TO VIEW FIGURE 1:
EXPECTED ELECTRICITY PRODUCTION IN EUROPE

Wind and solar energy are not continuously available and are difficult to predict precisely. Reserve power generating capabilities must therefore be provided which can be activated quickly in the event of the failure or limited availability of a renewable energy source that is caused by, for example, a lack of wind, too much wind, clouds or night.

Power plants fired by fossil fuels are the obvious choice here, primarily those driven by gas turbines, as they can be started up at relatively short notice. The inherent inertia of other types of power generating facilities is usually much greater, making them largely unsuitable for use as rapidly available reserve sources of power.

There are, of course, other fast-responding sources of power, such as pumped-storage plants, but they do not provide enough capacity to cover the entire installed generating capability of renewable power sources in the European grid system.

If we look into the future we see the percentage of renewable power generation installed in Europe increasing to about 30 per cent by 2030. This development is the result of international commitments, such as the Kyoto Protocol, to reduce CO2 emissions. This means that the significance of the fleet of plants fired by fossil fuels as a power reserve will continue to grow in the future.

Figure 2 illustrates how the daily load profile of intermediate load plants, especially CCPPs driven by gas turbines, is impacted by fluctuating renewable generation on the one hand and changing daily electricity demand on the other.

CLICK TO VIEW FIGURE 2:
SCHEMATIC OF DAILY LOAD PROFILE AND IMPACT ON CCPP
How can gas and steam help make power generation even greener?

Siemens’ highly efficient and fast cycle power plants have the flexibility to allow more renewable power in the grids.

Combined cycle power plants (CCPPs) from Siemens already are the cleanest fossil power generators today, paving the way for more clean, renewable power in the grids. Limited availability and predictability of wind and solar power challenges supply security. Innovative, fast-cycling technology in Siemens plants improves system stability, especially when it comes to highly fluctuating infeed from renewable sources. With a startup time that is setting industry standards, high load ramps, and frequency support capability, Siemens CCPPs perfectly complement the growing share of renewable power at highest fuel efficiency and lowest CO2 and NOx emission levels. [www.siemens.com/energy](http://www.siemens.com/energy)

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The new demand for extremely fast power generating availability is also becoming apparent in our customer assessments. Whereas some customers made absolutely no assessment of startup times only a few years ago, the assessment figures have increased in recent years in some projects to over €100,000/minute ($131,000/minute).

3. FACY CONCEPT

The idea of focusing plant design on an increased number of fast starts originated in experience of market conditions and executed projects. A multidisciplinary team of component and plant experts was formed around 2002 for the steam turbine, gas turbine, balance of plant and auxiliary systems, control technology and steam generator to identify potential improvements in existing plant concepts. The team identified several areas of potential improvement.

Different technologies could be used to maintain pressure and temperature in the main components during shutdowns. Such technologies include those for a stack damper and auxiliary steam. Another area for potential improvement is the 'ready-for-operation' mode of the water/steam cycle in which a fully automated start-up sequence called 'start on the fly' would allow a nearly unrestrained optimization of the automation and control concept. Finally a start-up operation concept. This allows the operator to predetermine component start.Optimized component design is another, for example high-capacity steam generation, which means that conventional separation of steam and boiling water inside a boiler drum is not necessary. Steam is generated directly within the evaporator tubes of the Benson-type boiler, so these limits do not apply. A temperature controlled start-up process, which uses an optimized high-capacity de-superheater to limit steam temperatures during the start-up process has been developed for warm and cold starts. This reduces thermal stress in the critical components of the steam turbine.

The application of the Benson HRSG allows the number of permissible start-ups and cycling events over the plant lifetime to be increased because stress-induced fatigue in the high-pressure section of the HRSG is reduced. To enhance the start-up procedure, the condensate polishing plant can be used to more quickly bring the water/steam cycle within specified limits for chemistry. The main feature of Benson boiler technology is once-through steam generation, which means that conventional separation of steam and boiler water is not necessary. Steam is generated directly within the evaporator tubes of the boiler, as shown in Figure 4. There is no high-pressure drum in a Benson-type boiler, so these limits do not apply. A temperature controlled start-up process, which uses an optimized high-capacity de-superheater to limit steam temperatures during the start-up process has been developed for warm and cold starts. This reduces thermal stress in the critical components of the steam turbine.

The application of the Benson HRSG allows the number of permissible startups and cycling events over the plant lifetime to be increased because stress-induced fatigue in the high-pressure section of the HRSG is reduced.

CLICK TO VIEW FIGURE 3: FACY FEATURES

All of the FACY features described in this paper will now discuss help to reduce startup time significantly. They are modular and will be offered, configured and implemented on a project specific base.

3.1 PRESERVING WARM START CONDITIONS

One area of focus when it comes to components is the steam generator. Major heat loss occurs through the stack and therefore a stack damper has been deployed to limit heat loss during shutdown. The cooling of the boiler is considerably reduced and delayed. Furthermore auxiliary steam can be used to heat the main HRSG. These measures clearly increase the maximum possible shutdown periods during which criteria for hot and warm starts still apply.

3.2 READY-FOR-OPERATION MODE OF THE WATER/STEAM CYCLE

Auxiliary steam is also used to maintain the water/steam cycle in a ready-for-operation mode. This means auxiliary steam is fed into the gland steam system of the steam turbine. Keeping the gland steam system in operation prevents air from being drawn into the steam turbine and the condenser. Since the steam turbine and the condenser are sealed-off from the ambient air, the condenser vacuum pumps can maintain vacuum. To enhance the startup procedure, the condensate polishing plant can be used to more quickly bring the water/steam cycle within specified limits for chemistry.

3.3 OPTIMIZED COMPONENT DESIGN AND PLANT OPERATION TO REDUCE MATERIAL FATIGUE

The high-pressure drum of the HRSG is one of the most critical components involved in the startup and ramping procedure. As a thick-walled component it is exposed to large temperature gradients and high operating pressures. Thermal stress in the high-pressure drum walls limits the load, start-up and shutdown gradients of the HRSG.

The main feature of Benson boiler technology is once-through steam generation, which means that conventional separation of steam and boiler water is not necessary. Steam is generated directly within the evaporator tubes of the boiler, as shown in Figure 4. There is no high-pressure drum in a Benson-type boiler, so these limits do not apply. A temperature controlled start-up process, which uses an optimized high-capacity de-superheater to limit steam temperatures during the start-up process has been developed for warm and cold starts. This reduces thermal stress in the critical components of the steam turbine.

The application of the Benson HRSG allows the number of permissible start-ups and cycling events over the plant lifetime to be increased because stress-induced fatigue in the high-pressure section of the HRSG is reduced.

CLICK TO VIEW FIGURE 4: DRUM-TYPE HRSG VERSUS A BENSON-TYPE HRSG

3.4 AUTOMATION CONCEPT OPTIMIZATION

There are two approaches to optimizing the automation concept. In the first, design limits are enhanced by the use of closed-loop control instead of earlier empirical approaches. In the second, a turbine stress controller is used to determine thermal stress based on temperature differences measured in the steam turbine. This ensures that stress limits are not exceeded. The turbine stress controller makes it possible to shorten the startup time without reducing the lifetime of heat-critical turbine components.

Two additional startup modes were introduced in addition to the normal mode. These were ‘fast’ and ‘cost-effective’. The operator has the option of choosing the appropriate startup mode depending on current electricity market prices and operating and power supply requirements. Maintenance intervals can be extended using the
3.5 SECOND GENERATION FACY. ‘START ON THE FLY’

In addition to the original FACY concept, a procedure for parallel startup of gas and steam turbines has been developed. It is based on monitoring and controlling the temperature gradients within limits acceptable for all critical plant components and on long-term operating experience with different steam conditions in Siemens turbines. The new concept enables plant startups without any gas turbine load hold points. A new startup sequence was implemented for this reason (see Figure 5). The main innovation is the early steam turbine starting point with earlier acceleration and loading of the turbine.

4. GRID SUPPORT

In liberalized electricity markets, the minimum requirements with respect to the power dynamics of power plants are defined in grid codes. Some of the most stringent requirements imposed on plant dynamics are to be found in the UK grid code because of its island character. Here we are focusing on three of the most critical dynamic properties: load stabilization at low frequencies, primary and secondary frequency response, and island operation capability.

4.1 LOAD STABILIZATION AT LOW FREQUENCIES

Normal fluctuations in the balance between generation and consumption are reflected in fluctuations in grid frequency, which can be compensated for by means of regular frequency control. The frequency can, however, also decrease or even increase more significantly in the event of unusually serious or uncommon disturbances.

Unfortunately a decrease in grid frequency also means a reduction of speed and subsequently a decrease in power output. This decrease in speed causes the compressor in the gas turbine to transport a reduced volumetric flow, thus decreasing gas turbine output if appropriate measures are not implemented to compensate for this behaviour, which has physical causes.

To counteract this decrease in power output, Siemens relies on several measures to increase output at short notice. The decrease in output can be compensated for by rapidly opening the guide vanes on the compressor. This increases fuel flow. This can compensate for a drop in power of around 6 MW.

In unfavourable operating conditions this increase in output will not be sufficient on its own to meet the requirement described above. However, in this case the Siemens patented fast wet compression concept can be used to mobilize a further power reserve of around 12 MW. Here demineralized water spray is temporarily injected at the compressor inlet. The mass of the injected water increases the mass flow through the compressor. The evaporating water also cools the air flow at the compressor inlet. This cooling increases the air density and consequently the mass flow through the compressor.

Rapid activation of the system constitutes a challenge to control systems as the increase in power output only takes effect at short notice if the gas turbine control and the water injection are perfectly coordinated through the optimized I&C system. The implementation of these grid-support features has been validated and demonstrated in the F-class multishaft...
The measurements from the Marchwood project in the UK are illustrated in Figure 10. It is clear that an 18 MW increase at each gas turbine was achieved by opening the compressor inlet guide vanes (IGVs) and then initiating fast wet compression, thus meeting the requirement of the UK grid code.

Click to view Figure 10: Load Stabilization in the Low-Frequency Test for Each Gas Turbine at the Marchwood Plant in the UK

4.2 Primary and Secondary Frequency Responses

The purpose of load stabilization at low frequencies was to prevent further destabilization of the grid when large disturbances make the frequency decrease. Primary and secondary frequency responses are now required for grid support during normal operation. For this purpose the UK grid code stipulates that a power plant operating at part load must be capable of making additional power available on a temporary basis. Figure 11 illustrates the requirement of the UK grid code.

Click to view Figure 11: Frequency Response at Low and High Frequencies in Accordance with the UK Grid Code

We can see from the diagram that the power plant operating at under 80 per cent load must be able to make available at least 10 per cent of its rated power within ten seconds in the event of a decrease in frequency. For secondary frequency response 10 per cent of its rated power must be made available within 30 seconds. As we can see from Figure 11, the requirements are reduced in the event of loads of over 80 per cent.

Figure 11 also shows that the load must be reduced by 10 per cent of its rated power within ten seconds in response to over-frequencies. The island operation requirement is, however, even more stringent than this criterion. For this reason this paper will not discuss the high-frequency response any further at this point.

Unlike load stabilization at low-frequency, there is no need to look for a further power reserve in this case. No new systems are required for this reason. The challenge lies more in the speed at which the power must be made available. To meet the requirements of the grid code, Siemens relies on fast repositioning of the compressor IGVs on the one hand. On the other hand, the fuel control has been optimized to such an extent that load ramps are possible without destabilizing combustion. Figure 12 illustrates the results of the test in Marchwood and clearly shows that the required additional power is achieved both after ten seconds and after 30 seconds. In fact the criterion is significantly exceeded in both instances.

Click to view Figure 12: Frequency Response Test at Low Frequency at Marchwood in the UK in July 2009, Data Are for One Gas Turbine

4.3 Island Operation Capability

In the preceding sections, the focus has mainly been on increasing power output. With island operation capability the primary objective is to stabilize the island grid. In this case it may happen that an excess of power in the island that has formed is suddenly faced with an abrupt drop in consumption. The grid frequency increases very quickly as a result. The power plant must react to this frequency increase by throttling power to stabilize the frequency without causing a forced shutdown of the power plant because of over-frequency or any other uncontrolled process. Uncontrolled shutdowns of power plants can result in a grid collapse. This is why the UK grid code stipulates that the power plant must in the worst case scenario be capable of decreasing 10 per cent of its rated power to the design minimum operating level (DMOL).

The DMOL must not be less than 55 per cent of rated power in this case. This load reduction must be effected so quickly that the island frequency remains below 52 Hz. Grid studies based on the UK National Grid requirements show that the load reduction must take place within around eight seconds.

The power plant must detect island formation of this kind automatically and take immediate action. As soon as island operating mode is activated, permitted load change ramps are set to the maximum value. The IGVs in the gas turbine compressor are closed without delay. At the same time the different closed-loop controls ensure that the power is decreased at the maximum rate of change for load. Flame stability and avoidance of potential flashbacks in the combustion system is the main objective of closed-loop control optimization. Achieving this goal avoids emergency shutdown of the gas turbine.

As we can see from Figure 13, during the Marchwood test the gas turbine output was decreased by 52 per cent within four seconds without initiating a plant trip – as the result of a simulated fast frequency increase of 0.9 Hz.

A further decrease of 4 per cent was achieved in the following four seconds. That also more than met the second grid code requirement.

Click to view Figure 13: Island Operation Test at the Marchwood Plant in the UK with One Gas Turbine
Meanwhile these basic plant features demonstrated in F-class plants are being transferred to H-class technology and were validated in open cycle operation at Inching 4 in Germany last year (see Figure 14), demonstrating that even this latest and highest efficiency technology is capable of supporting the same stringent grid code requirements.

**CLICK TO VIEW FIGURE 14:**
**GRID CODE TEST AT THE IRSCHING 4 PLANT IN GERMANY IN OPEN CYCLE MODE (SSCS-8000H)**

### 5. CUSTOMER BENEFITS

The previous sections clearly demonstrate that FACY and ‘start on the fly’ permit a reduction in startup times and allow operating modes with an increased number of startups. These features optimize the cycling regime of a plant.

An operating regime that permits a larger number of startups and thus enables nightly power plant shutdowns offers two additional benefits. First, CO₂ emissions are minimized by shortening inefficient plant startup times thanks to an optimized startup procedure. Maximum electrical efficiency is reached more quickly and total emissions are reduced. Second, since nightly shutdowns and reliable startups become economically feasible, overall CO₂ emissions are further reduced as inefficient overnight parking at part load is avoided. Other power plants within the grid can then be operated at full load and maximum efficiency.

Customers benefit from this, primarily through fuel savings and a reduction in CO₂ emissions during the startup phase. Shortening the startup time by using ‘start on the fly’ for a hot start offers an estimated added value of more than €3 million alone, assuming that the savings described above are realized over the service life of a 430 MW power plant. The option of disconnecting the plant from the grid overnight offers enormous potential in the form of savings in operating costs.

Night-time electricity prices are at such a low level in Europe that a shutdown using FACY compared with night-time part load operation offers an economic benefit for every start. The example in Figure 16 is based on a gas price of €20.2/MWh, CO₂ costs of €2.88/MWh and a night-time electricity price of €29.4/MWh. The performance data are based on a SCCS-4000F single-shaft with a cooling tower.

Today grid support features are primarily specified by the grid access requirements of the individual countries. No monetary valuation of the additional plant flexibility is included in tender specifications as yet. For this reason today’s plants are designed purely based on grid code specifications. Depending on the level of electricity market liberalization, different flexibility features allow additional earnings, mainly through participation in the frequency reserve market. Furthermore, plants with high reliability and operational flexibility when it comes to their behaviour under disturbed grid conditions are expected to be prioritized for dispatch.

### 6. CONCLUSIONS

Siemens, as an original equipment manufacturer and turnkey power plant provider, has successfully implemented a new plant feature called FACY to enable the highest operational flexibility with fast startup times and an increased number of possible startup events. FACY is a fully integrated plant concept that comprises optimizations of turbine design, HRSG, water/steam cycle, startup sequence and automation concept. One advanced FACY feature is the implementation of a stress controller to enable the plant operator to choose between fast, normal and cost-effective startup modes depending on service intervals and life consumption.

In the light of these preconditions and the high startup reliability of CCPPs, the economic solution for reducing the impact of night load losses. This
maximized operational flexibility in combination with a maximum efficiency of over 59 percent with the Siemens SCC5-4000F plant concepts ensures a higher dispatch rate compared with conventional power plants.

FACY also significantly increases plant startup efficiency and, in combination with a nightly shutdown mode, clearly reduces CO₂ emissions and increases overall power plant profitability.

In addition to the optimization of startup procedures and an increase in the number of permitted starts, Siemens offers a plant design that can even meet very stringent grid requirements, for example in the UK. This is only possible if the plant is designed using an integrative approach. Closed-loop controls allow plant potential to be utilized to the full. A fast wet compression system is activated to maintain power output in the event of low grid frequency.

The Marchwood plant has demonstrated that all the strict UK grid code requirements with respect to plant flexibility can be fulfilled while keeping maximum efficiency at more than 58 percent. These proven concepts and technologies are now ready for transfer to future F-class and H-class CCPP projects to support the increasing grid support requirements concerning operational flexibility.

The newly introduced features and concepts will help to secure the reliability of the supply of power and of grid stability, and enable the fast-growing market penetration of discontinuous renewable power generation to further reduce CO₂ emissions in Europe.
Power Generation Fuel Flexibility with High-Hydrogen Syngas Turbines

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ABSTRACT
The European power generation segment is experiencing challenges from disruptions in conventional fuel supplies, surging interest in renewables and technical advances that permit the efficient use of abundant coal resources.

Uncontrolled carbon from coal plants exceeds alternatives fired by natural gas by more than two to one. This is due, in large part, to greater fuel carbon content and lower overall energy conversion efficiencies. The energy sector would play a central role in curbing these gases through improvements in efficiency and rapid switching to low-carbon technologies, including carbon capture and storage (CCS).

Coal gasification and associated fuel gas process treatment provide mechanisms to effectively separate carbon components on a pre-combustion basis, leaving essentially carbon-free hydrogen fuel available for combustion within the combined-cycle power plant. Syngas fired combustion turbines should play a significant role in helping meet this generational challenge as the primary energy conversion unit for hydrogen to power.

Worldwide, GE Energy is a leader in the power generation industry in fleet size and range of gas turbines operating on a broad spectrum of fuels, including hydrogen-rich syngas. GE Energy turbines have demonstrated reliability, availability and performance using syngas from coal, an abundant and low-cost feedstock. Through operating experience, leadership and global alliances, GE Energy continues to address power generators’ strategic challenges by investing in the development of flexible integrated solutions such as phased integrated gasification combined-cycle (IGCC) power plants with high-hydrogen fuel capabilities for advanced gas turbine platforms.

GE Energy continues to develop combustion designs not only to extend this experience to advanced gas turbine platforms, but also with an eye on reducing or eliminating diluent requirements for emission and carbon control. The ever-present focus on efficiency improvement and emissions and carbon reduction, combined with improved gasification processes, is expected to require advanced combustion system configurations that can achieve low emissions and carbon capture at higher firing temperatures with little to no dilution of nitrogen oxides (NOx) abatement. These advanced combustion systems will extend the well established benefits of pre-mixed combustion to the highly reactive high-hydrogen fuel streams that will characterize a carbon-constrained power generation segment.

This paper provides an overview of the new fuel landscape evolution facing the challenge of low carbon dioxide (CO₂), with a particular focus on high-hydrogen combustion and innovative solutions like IGCC and syngas turbines for generation with a carbon conscience.

1. INTRODUCTION
The global energy landscape is experiencing major changes due to economic shifts and increased environmental awareness. As nations look for domestic energy security, limits to environmental impact and reductions in the effect of variable fuel costs, there has been a continued push to examine alternative or non-traditional fuel sources.

Combined-cycle gas turbine power plants provide high-efficiency power generation across a variety of fuels (see Figure 1). In many regions, natural gas will continue as the primary fuel of choice, but in other regions, coal will be used as a primary power generation feedstock. In those regions, coal offers energy stability and security.

CLICK TO VIEW FIGURE 1: HDGT FUEL SPACE
With continued awareness of the potential impact of GHGs on the global climate, many governments are looking for solutions to curb these gases.

These solutions for reducing CO₂ can be as simple as deploying increasing energy conversion efficiency or switching to lower carbon fuels.
Fossil fuel-based power generation creates multiple challenges for the power generation developer or planner: legislative and regulatory uncertainty (i.e., CO₂ regulations and carbon tax for example), political and environmental policy (carbon capture ready), return on investment for shareholders, level of technology readiness and the drive for lowest cost.

Options for dealing with the inherent carbon content in fossil fuels include: reducing power demand via energy efficiency and power conservation; switching to low-carbon fuels and low-carbon energy sources; altering power generation plants, in other words, shifting to technologies that reduce carbon output, and replacing or modifying existing systems by replacing older plants with newer, more efficient units. Plant upgrades can take many forms but can include plant efficiency improvements and retrofitting with carbon capture systems.

2. SOLUTIONS FOR REDUCED CARBON

As global attention is directed at carbon reduction, the use of high-carbon fuels such as coal may require systems for carbon capture. Carbon capture can be done in pre-combustion or post-combustion systems. Pre-combustion carbon capture can be performed on a variety of fuels, including natural gas and coal (see Figure 2). In gasification, coal is converted to a syngas — hydrogen ($H_2$) and carbon monoxide (CO) — from which carbon can be extracted on a pre-combustion basis using a shift process. This leaves a syngas of $H_2$.

The resulting decarbonized fuel is a high-hydrogen syngas with varying levels of nitrogen (N₂). Gas turbine power generation systems are capable of supporting various levels of carbon capture: 50–65 per cent carbon capture to meet near natural gas equivalency, or 90 per cent carbon capture for enhanced recovery (EOR), carbon sequestration or other industrial applications. In the case of carbon capture of greater than 65 per cent, the level of $H_2$ to the turbine is capped and additional increases in $H_2$ must be matched with increasing levels of dilution.

3. EXPERIENCE WITH SYNGAS TURBINES

Gas turbines can operate on a variety of low-BTU fuels, including shifted (high-hydrogen) and non-shifted syngas ($H_2$ and CO). To date there are more than 30 GE turbines operating on low-BTU fuels and these turbines have accumulated over one million operating hours (see Figure 3). These plants offer industry-standard availability of greater than 90 per cent and operate in a variety of power, industrial and petrochemical plants.

Our syngas turbine operating experience includes facilities that use oxygen-blown gasification technologies from GE and other suppliers, and a variety of fuels including high and low-sulphur coals, heavy oil and petroleum coke.

4. 7F SYNGAS TURBINE

The 7F Syngas turbine (see Figure 5), is GE’s latest F-class turbine product. It focuses specifically on using syngas and low-BTU fuels. This turbine has an ISO rating of 232 MW when operating with oxygen-blown, medium-BTU syngas fuel.

There are a number of physical differences between the 7F Syngas and existing syngas and natural gas turbines. This turbine uses the 7FB compressor, which enables a higher flow-to-pressure ratio capability and significantly improves output and efficiency across the baseload operating range. This turbine also includes an enhanced hot gas path (HGP) for use with syngas fuels, which includes aerodynamic improvements to the turbine section to accommodate the increased mass flow that occurs with syngas and diluent. The 7F Syngas turbine also uses 7FA HGP materials with proven corrosion resistance in syngas operating environments.

GE has experience of operating B-class and E-class turbines on high-hydrogen fuels. The $H_2$ content in the fuel ranges from approximately 50 per cent by volume to approximately 95 per cent. As power generation platforms capable of operating on high-hydrogen fuels enable the use of pre-combustion carbon capture systems, the ability to operate on various $H_2$ ranges becomes increasingly important.

One such system, the IGCC plant, has multiple advantages. When used with carbon capture, these plants would have a smaller carbon footprint than a new pulverized coal plant or an existing traditional coal plant. An IGCC plant that operates with greater than 65 per cent carbon capture could have a smaller footprint than a natural gas combined-cycle plant (see Figure 4).
for high reliability, and GE’s proven multi-nozzle quiet combustion (MNQC) syngas-combustion system. The first two units have been manufactured and have been shipped to the Duke Edmondsport IGCC plant in southwest Indiana, USA. This IGCC plant will have a net output of nearly 630 MW and COD is scheduled for 2012.

5. 9F SYNGAS TURBINE
The 9F Syngas turbine (see Figure 6) is based on the successful 9F-class heavy-duty gas turbine. This design is built on the experience of GE’s F-class HDGT products, which collectively have accumulated more than 31 million hours of operation, establishing GE as an industry leader for advanced technology gas turbines.

5.1 PRODUCT FEATURES & FLEXIBILITY
GE’s 9F Syngas turbine employs GE’s F-class product experience and incorporates a number of advances in technology, including GE’s low-BTU fuel MNQC system; advanced Mark VIe controls (Mark being a GE trademark), and robust compressor and turbine systems that allow for operation with increased torque and temperature.

The MNQC combustion system was built to operate on low-BTU fuels and is a proven technology that has been in use since the 1990s. This same combustion system has been installed on the 7F Syngas turbine units being delivered to the Duke Edwardsport IGCC plant in the US.

The 9F Syngas is configured with flexibility for compressor air extraction, allowing for integration in a variety of power plant cycles. The 9F Syngas can also be integrated into a high-hydrogen fuel stream from plants equipped with a carbon capture system. Accordingly the fuel envelope for the 9F Syngas turbine is designed to allow operation on a range of fuels, including natural gas, syngas (unshifted) and high-hydrogen (shifted syngas). The hydrogen content in the fuel can vary from 20–100 per cent. However, concentrations above 65 per cent may require additional nitrogen dilution.

5.2 PERFORMANCE
Operating on syngas, the 9F Syngas is capable of generating 293 MW in simple cycle operation. Operating on a fuel which is more than 60 per cent \(\text{H}_2\) delivers 304 MW. Using diluent injection (\(\text{N}_2\) or steam) the 9F Syngas can achieve NOx emissions of 25 ppm with either fuel type.

The 9F Syngas turbine provides a wide range of syngas fuel and process integration flexibility and can operate on fuels produced from a variety of GE and non-GE gasification technologies that meet or exceed specification limits. Based on significant gas turbine and syngas experience, the 9F delivers high efficiency and reliability for advanced IGCC plants.

5.3 PHASED IGCC
As carbon policy is uncertain, some utilities are reluctant to invest in coal-based power generation solutions. However, coal is an abundant, low-cost fuel resource in many regions and there is a continual need to replace aging assets and, in some global regions, to increase baseload capacity. A phased IGCC approach is an option that allows for initial natural gas operations while keeping the potential for syngas operation available in the future.

In phased IGCC the initial turbine configuration is a 9FA with a dry low-NOx (DLN) combustor operating on natural gas fuel. When the regulatory environment or economic factors warrant a switch to syngas, the turbine can be easily converted to a 9F Syngas configuration. During this conversion, the DLN combustor is replaced with an MNQC, GE’s standard syngas combustion system. In addition the 9FA stage 1 nozzle (SN1) would be replaced with a nozzle having a larger flow area to accommodate the increased mass flow that occurs with syngas operation.

When contemplating this phased IGCC approach, it is important to understand plant differences when operating on syngas. Depending on the level of integration, there could be increased steam flows to and from the bottoming cycle, resulting in the potential for increased power production from the steam turbine. There can also be increased power generated by the gas turbine while operating on syngas.

To avoid issues post-conversion, major capital equipment, such as the steam turbine, generators and HRSG, should be sized to accommodate syngas power output levels. In addition, if carbon capture is being considered as part of the conversion, the space required for the capture and compression system must be considered. There is even flexibility in returning to operation as a DLN unit if gasification operations are suspended at a future date.

6. FUTURE DEVELOPMENTS
In addition to the developments ongoing for the 9F Syngas turbine, GE Energy is working on the technologies needed to advance the capabilities of the next generation of gas turbines for coal IGCC applications that include carbon capture. This is being done under a cooperative agreement with the US Department of Energy (DOE) entitled ‘Advanced IGCC/Hydrogen Gas Turbine Development’ (contract number DE-FC26-05NT42643).
While today's turbines operate effectively and reliably on various syngas fuels, including high-hydrogen fuels, there is a need to do this at higher efficiency, with reduced combustion NOx emissions and at lower cost. This is particularly important for coal IGCC with CCS, as improvements in the turbine can help offset some of the penalties associated with CCS.

The GE/DOE programme seeks to develop and demonstrate technologies that may increase IGCC combined-cycle efficiency by 3 –5 percentage points at 2 ppm NOx at 15 per cent O\(_2\) and contribute to a significant reduction in IGCC plant cost in $/kW.

During the first two years (phase I) the focus was on determining which new turbine technologies would be required to meet programme objectives. A mix of combustion, turbine and materials technologies were selected for development based on systems analysis that translated expected component improvements to the plant level.

Additionally in phase I the development work itself was initiated for several of the key technology areas, as jugular laboratory tests and analysis were performed to establish entitlement capability. In late 2007, the programme transitioned to phase II, where the emphasis is now fully on component development and validation. This phase is targeted for completion by early 2012.

The combustion goal for the programme is "reliable, ultra-low NOx combustion of high-hydrogen fuels for advanced gas turbine cycles". This means achieving the NOx levels at the targeted high operating temperatures while avoiding flashback, achieving a relatively low pressure drop, managing dynamics and expanding fuel flexibility.

In phase I the NOx entitlement characteristics for the fuels of interest were mapped over the targeted temperature range and the effects of the major NOx drivers quantified. Using a single-nozzle test rig and supporting analysis, testing and iterative improvements were performed on multiple concepts.

Over 30 concepts were evaluated. Near-entitlement NOx emissions were achieved and two of the advanced concepts were selected for continued development in phase II of the programme. In phase II, focus shifted from single nozzles to a full-can size with multiple nozzles. The DOE 2010 targets were achieved with low single-digit NOx for operation on 100 per cent premixed syngas at F-class conditions.

Later in phase II the DOE 2012 targets were achieved with single-digit NOx for operation on high-hydrogen fuel (60–100 per cent H\(_2\) by volume) in excess of F-class conditions. System pressure drop and dynamic responses were also favourable. A level of reliability and durability on H\(_2\) fuel was also demonstrated with over 50 hours of fired test time in 2009, including several instances of full load operation for more than 6 hours. Promising performance was retained on syngas and natural gas fuels. Figure 7 shows video image capture of the flame image from a full combustion chamber operating at F-class conditions on H\(_2\)–N\(_2\) fuel.

7. CONCLUSIONS

As fuel landscapes continue to evolve, IGCC can play an important role in low-carbon power generation. GE’s heavy-duty gas turbines are ready to support IGCC and syngas operations for a variety of applications. Specifically GE's 9F Syngas turbine is capable of supporting IGCC applications with and without carbon capture. In addition, in recognizing the uncertainty of carbon policy, this turbine is capable of supporting phased IGCC, allowing for flexible power generation.
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Development of a New 1600 ºC Turbine Inlet Temperature Large Frame Gas Turbine for High Combined-Cycle Efficiency

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ABSTRACT
Worldwide concerns about global warming are pushing gas turbine design parameters towards operating conditions never experienced before. Increased turbine inlet temperature (TIT) and higher compressor ratio offer a path toward increased combined-cycle efficiency but also present engineering challenges. Combined-cycle power plants firing natural gas provide one of the cleanest and most efficient hydrocarbon-based generation alternatives. These plants can be designed for large capacity and are relatively fast to build.

Mitsubishi Heavy Industries (MHI) is actively working on a variety of different technologies to reduce the generation of greenhouse gases and other polluting emissions. This includes the design and manufacture of high-efficiency natural gas burning combined-cycles. Through this effort, a new gas turbine frame called ‘J-series’ gas turbine (M701J and M501J for 50 Hz and 60 Hz versions, respectively) was recently launched. This new frame will operate at an unprecedentedly high TIT of 1600 ºC and a pressure ratio of 23:1.

This steam-cooled engine is based on the experience gained with the ‘G’ series and incorporates state-of-the-art technology developed in the Japanese National Project, which is in pursuit of an even higher TIT. The incorporated technology includes advanced cooling, improved turbine aerodynamics and advanced thermal barrier coating (TBC).

This paper describes and discusses the design features and development status of the J-series gas turbine in both 50 Hz and 60 Hz versions.

1. INTRODUCTION
Figure 1 shows the recently announced J-series gas turbine.

This new machine features the largest power generation capacity and highest thermal efficiency currently offered. The J-series was designed to operate at 1600 ºC TIT, which is 100 ºC higher than its predecessor, the G-series.

CLICK TO VIEW FIGURE 1:
ISOMETRIC VIEW OF THE M501J GAS TURBINE

The resulting higher exhaust gas temperature will be effectively used in combined-cycle application (Figure 2).

Combined-cycles based on the J-series gas turbines are expected to operate at 61 per cent efficiency (LHV), exceeding the efficiency available through existing combined-cycle technology.

The Kyoto Protocol came into effect in February 2005 in an effort to reduce global warming. Japan is committed to reduce by 6 per cent its total carbon dioxide [CO2] emission levels of 1990, between 2008 and 2012. In 2009, the Japanese government pledged to reduce the total CO2 emissions of 1990 by 25 per cent by 2020.

CLICK TO VIEW FIGURE 2:
A BIRD’S EYE VIEW OF M501J COMBINED-CYCLE (1:1)

With this challenging target it has become essential to improve the thermal efficiency of the gas turbine for combined-cycle (GTCC). MHI has been involved since 2004 in the Japanese National Project for the development of an innovative and efficient combined-cycle power plant based on 1700 ºC TIT gas turbine technology. Several features of the J gas turbine were derived from this Japanese National Project. The new technology incorporated includes advanced turbine cooling, improved turbine aerodynamics and an advanced TBC.
Eiji Akita accepted the award on behalf of Dr. Koeneke.
2. THE JAPANESE NATIONAL PROJECT (1700 ºC CLASS)

Concerns about global warming have generated controversy over CO₂ emissions produced by the use of hydrocarbon fuels. Compared to conventional power generation facilities based on coal or fuel oil, high-efficiency combined-cycles, based on natural gas firing gas turbines, can reduce carbon emissions.

Based on Japan’s Basic Act on Energy Policy, enacted in 2002, an energy plan was approved by the Japanese cabinet in 2003. In response to this new plan, the Japanese Ministry of Economy, Trade and Industry (METI) is promoting the development of a high-efficiency gas turbine for power generation. This project pursues an aggressive efficiency target through the development of a 1700 ºC TIT class gas turbine. The combined-cycle efficiency for this ambitious project targets 62.65 per cent (Figure3). As part of this gas turbine project, core technologies are being developed and commercialized.

CLICK TO VIEW FIGURE 3:
JAPANESE NATIONAL PROJECT: 1700 ºC CLASS GAS TURBINE

3.1 TECHNOLOGY DEVELOPMENT FOR 1700 ºC TIT GAS TURBINE

The component development phase of this project took four years and was completed in 2007. During the first phase, several R&D efforts were carried out to develop key technologies for a 1700 ºC TIT class gas turbine. These efforts included:

- Exhaust gas recirculation combustor for lower emissions;
- Higher turbine cooling efficiency;
- Advanced thermal barrier coating;
- Higher pressure ratio compressor;
- Advanced heat resistant turbine materials;
- Enhanced turbine aerodynamics.

The development status of the above mentioned technology, including analyses and experimental results, are reviewed below.

3.2 ADVANCED TURBINE COOLING TECHNOLOGY

The blades of a 1700 ºC class gas turbine are exposed to a high heat load and thermal stress. High performance cooling schemes with a lower volume of cooling air are required in the turbine blades to improve thermal efficiency without negatively impacting their life. A hybrid cooling system combining closed circuit steam cooling and open circuit air cooling was extensively evaluated. In the Japanese National Project newly-developed cooling methods, which include high performance film-cooling, 180 degree-turn structure with low-pressure drop, semi-transpiration cooling, and high performance turbulence promoter are investigated experimentally.

Several types of film cooling hole shapes were considered and manufactured. Their film cooling effectiveness was measured with an infrared camera and laser induced fluorescence (LIF). The effectiveness of the advanced shaped holes was around 25 per cent higher than that of the conventional shaped holes (Figure 4).

CLICK TO VIEW FIGURE 4:
COOLING HOLES ON THE PLATFORM OF THE TESTED ROTATING BLADE (TOP) AND THE MEASURED FILM COOLING EFFECTIVENESS FROM EACH ROW OF COOLING HOLES (BOTTOM)

3.3 ADVANCED THERMAL BARRIER COATING (TBC) TECHNOLOGY

The application of the TBC is essential for high temperature gas turbines. In general, the cooled components, such as the turbine blades are coated with two different protective layers called ‘bond coating’ and ‘top coating’.

Powder alloys such as MCrAlY (M: Alloy elements such as Co, Ni, CoNi, etc.) are used for the bond coat material. The bond coat must have good adhesion properties and superior oxidation resistance. Ceramic powders with low-thermal conductivity such as ZrO₂ (YSZ: yttrium partially stabilized zirconium) are used as a top coat.

The resulting TBC is used for high-temperature gas turbines to reduce metal surface temperature of critical components. Several coating compositions were tested for the Japanese National Project. Evaluation of the experimental results (Figure5) shows that new top coat materials developed for this project have close to 20 per cent lower thermal conductivity than conventional YSZ-type without compromising durability. The evaluation of the long-term durability characteristics of the developed TBC is ongoing.

CLICK TO VIEW FIGURE 5:
RESULTS OF MEASURING COEFFICIENT OF THERMAL CONDUCTIVITY OF NEWLY DEVELOPED THERMAL BARRIER COATING

4. J-SERIES GAS TURBINE DESIGN FEATURES

The J-series will operate at an intermediate TIT between the current 1500 ºC technology and the 1700 ºC TIT involved in the Japanese National Project. This approach allows early application of the technology developed for the 1700 ºC TIT class gas turbine and provides initial validation of the technology at a lower temperature exposure. The 100 ºC TIT increase is key for achieving high combined-cycle efficiency but presents difficult technical challenges that are overcome through exhaustive R&D efforts and verification tests. J-series design features:

- 1600 ºC TIT;
- 23:1 pressure ratio (based on MHI’s H-class 25:1 compressor);
- Technology developed for the Japanese National Project;
- Advanced turbine cooling technology;
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J-SERIES GAS TURBINE PERFORMANCE

CLICK TO VIEW TABLE 1:
J-SERIES GAS TURBINE PERFORMANCE

The increased TIT represents the biggest challenge in the combustor development. MHI is leveraging its long steam-cooled combustor experience in the G-series gas turbine where excellent durability has been achieved. The steam flow rate can be adjusted to maintain the metal temperature of the combustor hardware. In addition, the state-of-the-art Japanese National Project technologies originally developed for 1700 ºC TIT gas turbine (Figure 9) are used to provide a smooth transition to this design.

CLICK TO VIEW FIGURE 9:
KEY TECHNOLOGIES FOR HIGHER TEMPERATURE

4.2 VERIFICATION TEST

The verification test of the J-unit for 60 Hz (M501J) will be conducted at Takasago demonstration facility (T-point). T-point is a demonstration combined-cycle plant based on the M501G gas turbine. It has been operated for more than 13 years facilitating verification of numerous G-class enhancements.

In 2010, the existing M501G1 unit will be replaced with a M501J gas turbine for verification of the new engine. The tests are scheduled to begin in 2011. Similar to the G-class experience, T-point operation will allow verification of the new J technologies, its performance and reliability (Figure 10).

The M701J is the 50 Hz of this new class. It was designed as a full-scale design of M501J (Figure 11). The validation of the M501J at T-point will provide useful feedback for the M701J.

CLICK TO VIEW FIGURE 10:
SCHEDULE FOR J-SERIES

5. CONCLUSIONS

MHI is actively participating in the Japanese National Project that targets 62 per cent to 65 per cent combined-cycle efficiency though the development of a 1700 ºC TIT class gas turbine. Several technologies developed for the National Project are applied to a new 1600 ºC TIT class gas turbine.

With a combined-cycle efficiency of 61 per cent, the J-series GTCC power generation will considerably reduce the CO2 emissions released by existing technology and therefore will contribute to reducing global warming.

The first M501J (60 Hz) will begin verification at T-Point in 2011 and the subsequent unit will be commercially available in 2013. The first M701J (50 Hz) will be ready for delivery in 2014.

- Advanced thermal barrier coating.
- High-efficiency, high loading turbine.

The J-series gas turbine maintains the basic structural design used in previous MHI large industrial gas turbines, as shown in Figure 6. This includes cold-end drive, two-bearing support, can-annular type combustor and 4-stage turbines to keep high reliability.

CLICK TO VIEW FIGURE 6:
MITSUBISHI LARGE INDUSTRIAL GAS TURBINES PROVEN DESIGN FEATURES

The J-series steam cooling design (Figure 7) is based on extensive steam cooling experience with the G-series, accumulated in 35 operating units with close to 900 000 actual operating hours and more than 9700 starts. Redundant steam supply sources are provided to maintain a steam cooling back-up source during all stages of operation. The steam cooling application helps maintain the nitrogen oxides (NOx) emissions within acceptable levels.

CLICK TO VIEW FIGURE 7:
MAIN FEATURES OF THE J SERIES GAS TURBINE

MHI introduces a new series of turbines for power generation every ten years. The J-series is expected to be the main turbine for the next ten years.

4.1 TARGET PERFORMANCE FOR GTCC

Figure 8 shows the evolution of TIT and its effect on efficiency and power output. In the 50 Hz version, the G-series demonstrated a combined-cycle efficiency in excess of 59 per cent (LHV) at a Tokyo Electric Power Company combined-cycle plant. The J-series combined-cycle is expected to achieve 61 per cent efficiency (LHV), while its power generation capacity will be approximately 20 per cent greater than that of the G-series.

CLICK TO VIEW FIGURE 8:
J-SERIES GAS TURBINE PERFORMANCES (EFFICIENCY & POWER)

Table 1 below shows the J-series gas turbine rated power output for 50 Hz and 60 Hz, in open and 1-on-1 single-shaft combined-cycle configuration. The high exhaust gas temperature is effectively used in combined-cycle application.

CLICK TO VIEW TABLE 1:
J-SERIES GAS TURBINE PERFORMANCE

“WITH A COMBINED-CYCLE EFFICIENCY OF 61 PER CENT, THE J-SERIES GTCC POWER GENERATION WILL CONSIDERABLY REDUCE THE CO2 EMISSIONS RELEASED BY EXISTING TECHNOLOGY AND THEREFORE WILL CONTRIBUTE TO REDUCING GLOBAL WARMING”
REFERENCES


POWER-GEN EUROPE

TRACK 4

COAL FIRING, BIOMASS COMBUSTION AND WASTE TO ENERGY
Large-scale Material Testing of On-line Corrosion Monitoring at the AEB High-efficiency WTE Plant

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ABSTRACT
Amsterdam’s waste and energy plant Afval Energie Bedrijf (AEB) has one of the largest single-site facilities for the production of energy from waste. The plant has been operating since 2007 and can produce more than 1 TWh per year. Its net electrical efficiency has risen from 20 per cent in 1993 to 30 per cent today. The plant has high operational steam pressure and temperature: 125 bar and 438 °C. This temperature is to be increased to 480 °C. It is known that the combustion of municipal solid waste in a waste to energy (WTE) boiler produces a corrosive environment for the material of the boiler tubes, so the 15/16 Mo3 water wall material has been pre-cladded with alloy 625.

Two planned and consecutive outages of the boilers offered a unique opportunity to begin an extensive and ambitious in-situ materials testing programme. The aim of this programme was to test state-of-the-art materials and application techniques under real conditions to be able to develop the most cost-effective maintenance strategy.

The in-situ material testing comprises: materials testing of thermal or high-velocity sprayed and welded materials based on corrosion probe exposure; large testing areas of thermal or high-velocity sprayed and welded materials which were applied in-situ; and testing of large-scale super-heater tube materials with wall thicknesses measured internally prior to placement.

The on-line corrosion monitoring programme was carried out in parallel with the materials testing programme in order to optimize the operational conditions and to minimize cost.

This paper will describe the material testing programme and the applied techniques. Furthermore operational conditions, such as boiler load, oxygen content, pressure and temperature were analysed statistically and linked with the corrosion rates. This paper will discuss in detail the results and the conclusion of the analyses.

INTRODUCTION
In view of global economic, social and environmental challenges, viable technologic solutions are required to help to overcome these challenges and reach the desired goals. Investment in energy efficiency is a must because of increasing demands for clean and efficient technologies worldwide, the long-term rise in the cost of primary energy and the cyclical downturn.

A WTE power plant is a never ending renewable energy source with high potential. But the burning of waste creates an aggressive environment for boiler components and can cause severe corrosion problems in incineration plants. The corrosion may result in loss of material and the periodic shutdown of plants. It also accounts for a significant increase in operational costs [1, 2].

AEB, formed in 1885, has been renovated four times with the latest commissioning in 2007. This fourth plant design is aimed at total reuse of energy and materials. The plant now produces electricity with an efficiency of 30 per cent. In 2007, this was the highest efficiency produced by a WTE plants anywhere in the world. The processing capacity of this plant is 530 000 tonnes per year raising the total processing capacity of AEB to 1.4 million tonnes per year.

Increasing the steam pressure and temperature is unavoidable if the efficiency of the Rankine cycle used in power stations is to be improved, as Josef Cizeret al have shown. An increase of steam temperature from 400 °C to 500 °C leads to an increase of 20 per cent in generated power [3]. The AEB’s steam temperature is 438 °C but will rise to 480 °C. Normal and maximum steam pressures
Fire-side corrosion or erosion can occur at the preference clock positions of tubes. This relates to gas flow or soot blower activity. Likewise this preference for attack at a certain clock position can take place inside the tube. A stacked A-scan from a calibration tube is shown in Figure 2. The scan length is in the horizontal direction and the sound path in the vertical.

CLICK TO VIEW FIGURE 2:
STACKED A-SCAN FROM A CALIBRATION TUBE USED IN THE MEASUREMENT OF EXTERNAL CORROSION

Fire-side corrosion or erosion can occur at the preference clock positions of tubes. This relates to gas flow or soot blower activity. Likewise this preference for attack at a certain clock position can take place inside the tube. A stacked A-scan from a calibration tube is shown in Figure 2. The scan length is in the horizontal direction and the sound path in the vertical.

CLICK TO VIEW FIGURE 3:
STACKED A-SCAN FROM A CALIBRATION TUBE FOR THE MEASUREMENT OF INTERNAL CORROSION

The attack on the tube is not usually regularly distributed along the tube circumference, axial scans are performed at more than one clock position. In practice, especially when no advance knowledge on this preference is available, the scanning takes place at three clock positions, straight above and at +45° and -45° to this first

In parallel with the material testing, the influence of the operating conditions on the corrosion rate was determined with the aid of KEMA on-line corrosion monitoring (KEMCOM).
position. The accuracy of the wall thickness measurement is proven to be better than 0.2 mm. Theoretically the minimum size of pit or flat-bottomed hole that can be detected depends on parameters such as probe distance, the kind of probe used and the curvature of the tube. The smallest flat-bottomed hole size measured for typical KEMBUS sensitivity is 3.5 mm in diameter.

Software was developed to convert the sound path difference to wall thickness and to present a plot of the wall thickness as a function of the scanned distance. Figure 4 shows such a plot for a calibration.

CLICK TO VIEW FIGURE 4:
SELECTED A-SCAN IN UPPER WINDOWS. BOTTOM WINDOW: WALL THICKNESS AS A FUNCTION OF DISTANCE SCANNED OF A CALIBRATION TUBE WITH OUTSIDE WALL THICKNESS STEPS

The minimum wall thickness recorded for a certain tube or scan is highlighted in colour in a drawing of the side view of the boiler in Figure 5.

CLICK TO VIEW FIGURE 5:
KEMBUS MEASUREMENT LOCATIONS AT BOILER 36 OF AEB, AMSTERDAM

Calibration tables for converting sound paths to wall thickness can be constructed with measurements on calibration tubes but also with computer calculations based on Fermat’s law.

[I] THE KEMBUS MEASUREMENTS AT AEB

The test areas in the front wall and in the roof section of the boiler were measured with a non-interfering NDT measurement technique. Normally ultrasonic measurements are designed and applied in non-destructive testing. However, the conventional way of conducting NDT measurements is from the fire side and requires some grinding to make the surface even for good sensor contact. These grinding activities are necessary but also influence the results.

Normally in the case of an Inconel weld overlay, this method is still applied for raster measurements, but the error of this form of measurement is high since the determination of the position coordinates for repetitive measurements is inaccurate. In the case of an uneven and rough surface, the error can be significant.

However, there are cases in which the error is accepted and the measurements are used for trending of water-wall wastage over the years.

The standard NDT raster measurement was not an option when comparing the applied materials. This was because the new applied surface needed grinding for NDT activities and would therefore interfere with the results. Therefore the KEMBUS approach was adopted, not only for the testing areas but for the complete first pass of all accessible boiler parts.

The fire-side wall thickness measurement includes two locations, as shown in Figure 5: roof and front wall. In the roof both the front and back side were scanned. In order to be able to conduct the KEMBUS measurements all of the insulation on the whole of the cold side of the water wall was removed in the first pass.

In the front wall, the measurement was carried out at 22 metres, 25 metres and 28 metres. In each location, there were 13 groups of tubes, marked A to M in Figure 5. Between six and eight tubes from each group were scanned from left to middle to right. An example of the ultrasonic KEMBUS results is shown in Figure 6.

CLICK TO VIEW FIGURE 6:
AN EXAMPLE OF KEMBUS SCAN TO MEASURE THE WALL THICKNESS FROM OUTSIDE THE BOILER

The wall thickness can be measured and calculated based on the ultrasonic signal shown in Figure 6. The results of the front wall thickness measurements are shown in Figure 7. The measured wall thickness outside the test areas varies between 7.1 mm and 8.7 mm. The wall thickness of the test areas is somewhat thicker due to the application of additional coatings or alloys.

CLICK TO VIEW FIGURE 7:
KEMBUS WALL THICKNESS MEASUREMENT OF THE FRONT WALL OF THE AEB BOILER IN 2009

The initial idea was to determine the performance after about six months. However, due to problems related to the steam turbine, start-up after the outage in 2008 was delayed. This left only three months of exposure until the next planned outage.

Taking the inaccuracy of the KEMBUS measurements into account, the first measurements after three months of exposure did not indicate that there were significant differences between the applied coatings and additional claddings. The next planned outage in either 2011 or 2012 will be the first opportunity to be able to determine the longer term exposure results.

EXPOSURE OF TEST COUPONS (KEMCOPS)

(I) INSTALLATION OF KEMCOPS

The principle of the KEMCOP is based on the integration of a small corrosion probe in a strip of membrane of the water wall. Fixing the probe in the strip allows the probe to be cooled. The integration of the probe in the water wall means it shows actual corrosion. The option to exchange the KEMCOPs during full-load operation is another advantage of the use of the KEMCOP in corrosion monitoring.

The probes were installed in different areas of boilers 35 and 36. The selection of the KEMCOP areas was based on the findings of a visual inspection carried out during the planned outage of boiler 35.
in 2008. Figures 8 and 9 show the KEMCOP locations in boilers 35 and 36, prepared on identical locations during their outages.

CLICK TO VIEW FIGURE 8:
KEMCOP POSITIONS IN BOILERS 35 (LEFT) AND 36 (RIGHT)

CLICK TO VIEW FIGURE 9:
GRAPHICAL PRESENTATION OF THE KEMCOP LOCATIONS

CLICK TO VIEW FIGURE 10:
TOP VIEW OF BOILERS 35 AND 36

From these actual water wall panels, M8-size tested coupons (KEMCOP) type corrosion probes were machined. The KEMCOPs were installed after the startup of the boiler and were exposed for several months. These probes were collected for analysis before the next planned outage in 2009. The advantage of this approach is that micrographs were able to be taken from cross-sections of the probes. These showed the adherence of the coatings and additional layers on the water wall material of the probes without destroying the water wall of the boiler.

The microstructure of an exposed coated KEMCOP is shown in Figure 11. The tested coupon was exposed in boiler 36 of AEB for three months. The results of all coatings are still under investigation and the conclusions to these tests will be presented in a future paper.

CLICK TO VIEW FIGURE 11:
CROSS-SECTION OF EXPOSED KEMCOP WITH COATING IN BOILER 35 IN LOCATION 1 (31 METRES)

THE PROCESS CONDITIONS

For the process or combustion conditions the boiler design is a non-interfering factor. The boiler control and design determine the boundaries of the process conditions. However, the process conditions influence the chemistry that the boiler parts experience, and therefore determine the nature of the corrosion phenomena. This means that optimization of the process conditions can lead to a reduction in the corrosion rate.

AEB is a modern WTE plant, so boiler 36 is equipped with an automated combustion control system. When the influences of the process conditions on the corrosion rate can be determined online, this automated combustion control system can be trained. An online corrosion monitoring programme (KEMCOM) was conducted at boiler 36 to train the control system.

II ONLINE CORROSION MONITORING

Corrosion is basically an electrochemical process in which anodic metal dissolution and cathodic reduction of ions occur simultaneously on the metal surface. An exchange of electric charge carriers is provided through the metal between the anodic and cathodic areas. The corrosion current, \( i_{\text{corr}} \), determines the corrosion rate, by Faraday’s law, and therefore indirectly the metal loss.

Most on-line corrosion-monitoring measurement equipment measures the polarization resistance \( R_p \). The LPR method measures the polarization resistance of a corroding electrode using sinusoidal polarization of the electrodes. The amplitude of this is small, about 2.5 mV. The polarization resistance is inversely proportional to the corrosion current.

Corrosion rates are calculated from the LPR measurement technique but the technique assumes steady-state conditions. So the LPR technique cannot measure localized corrosion. Measurements in low-conductivity electrolytes, such as deposits formed on superheater tubes, can give incorrect results if the electrolyte resistance is not considered and continuously calculated.

The electrochemical noise measurement technique was developed to detect localized corrosion, such as pitting and crevice corrosion. The signals obtained from electrochemical noise (ECN) measurement are the transient current and transient potential at an electrode. The corroding process on the electrodes generates the signals.

ECN is the small fluctuations in potential and current that occur on the surface of a metal at the free corrosion potential. ECN arises because of changes of anodic and cathodic areas. Small currents can be measured if the equilibrium potential is free. But a fixed current will not give rise to a fixed potential. The potential will fluctuate around a mean value.

The measurement setup must consist of three electrodes. The current noise is measured between two electrode pairs, while the potential noise is measured between the other two electrode pairs. The rationale for using this setup is that the potential noise and current noise are not directly measurable on one electrode. They are determined from the fluctuations between a pair of electrodes. In the three-electrode configuration the electrodes must be of the same material, the actual water wall material, and identical in size. This simplifies the field measurement where reference electrodes are difficult to use. When operating in the three-electrode mode the solution resistance measurement is used to give an indication of the solution conductivity.

(II) THE KEMCOM PROBES

KEMCOM is based on measurements of ECN. The first application of ECN-monitoring instrumentation for the evaluation of a high-temperature corrosion rate was conducted at UMIST in 1989 [5]. The advantages of being able to employ ECN in high-temperature systems are two-fold. First, it avoids the necessity of using a reference electrode, which can be difficult to arrange in high-temperature systems.

Second, the ECN technique is far less affected by measurement errors associated with changes in the solution resistance of the
electrolyte, which can be significant in high-temperature corrosion conditions.

In the case of the high-temperature sensor, ceramic spacers were used between the sensor elements, and the operating temperature of the electrodes was controlled using a cooling airflow.

Two types of sensors were developed: a flush-faced type that could be used to evaluate corrosion conditions in the membrane wall of the radiant section of the furnace, and a tube type that could be used to investigate high-temperature corrosion phenomena in the super-heater or reheater sections. The working faces of the radiant and super heater types of probe are shown in Figure 12.

A. THE CORROSION RATE
During the measurement the probe temperature was set at 400 °C. Only data recorded in a temperature range between 350 °C and 450 °C were analyzed. The results of the measurement are shown in Figures 16 and 17.

B. PROCESS OPTIMIZATION
More than 1200 operational conditions were analyzed and the results were grouped and shown in a surface map. Figure 19 is the surface map of the operational conditions of combustion air. The colour is used to show the correlation coefficient. When the coefficient is below 0.2 the colour is white. When the coefficient is 0.2 to 0.4 the colour is yellow, red when 0.4-0.6, and blue when 0.6 to 0.8. The surface map is also useful in that it helps display the operational effects on corrosion in different periods. Figure 19 makes clear that certain groups of operational conditions influence the corrosion rate, such as pressure and temperature of tertiary air, and pressure and flow of primary air in zones 3A and 3B.

Some operational conditions have little effect on corrosion behaviour, for example pressure of steam supply.

The sudden rise of the corrosion rate on 19 September 2009 can be explained by the fact that the decrease in pressure of the compressed air influenced the droplet size of the ammonia injectors in positions directly above the corrosion probes. Instead of spraying towards the centre of the first pass, they started dripping onto the probe tip.

The probe was taken out of the boiler and put back on 24 September 2009. It seems that there was no severe attack on the probe except ash deposits on the surface of the probe, as shown in Figure 18. This suggested that the radiant probe worked well in high temperature and can work for longer periods.

More than 1200 operational conditions were analyzed and the results were grouped and shown in a surface map. Figure 19 is the surface map of the operational conditions of combustion air. The colour is used to show the correlation coefficient. When the coefficient is below 0.2 the colour is white. When the coefficient is 0.2 to 0.4 the colour is yellow, red when 0.4-0.6, and blue when 0.6 to 0.8. The surface map is also useful in that it helps display the operational effects on corrosion in different periods. Figure 19 makes clear that certain groups of operational conditions influence the corrosion rate, such as pressure and temperature of tertiary air, and pressure and flow of primary air in zones 3A and 3B. Some operational conditions have little effect on corrosion behaviour, for example pressure of steam supply.
Figure 20 is the surface map of operational conditions of flue gas related to corrosion rate.

The general effects of operating conditions can be read in the surface map, but the detailed effects should be analyzed separately. Figure 21 shows the corrosion rate and the actual load. It seems that the corrosion rate always changed when the actual load changed. For example, the peaks on 20 August 2009 and 10 September 2009, circled in Figure 21, both reflect the actual load variation. It seems that when the actual load fluctuated, the corrosion rate started to fluctuate at the same time.

The optimization cannot be based solely on the corrosion measurements because there are multiple factors influencing corrosion. The first step is to determine the influencing factors based on the surface maps. The next step is to discuss the individual operational conditions with the operation engineers and to plan actions for a focused optimization programme based on a limited amount of operational conditions.

CONCLUDING REMARKS

The testing of the material is still ongoing. Because the first results were based on an exposure period of about three months, it is too early to draw conclusions about which the best performing materials are. The selected techniques KEMBUS and KEMCOP showed themselves to be effective in showing the performances of individual materials in the actual water wall based on NDT measurements and destructive analyzes based on test coupon exposure. The KEMBUS technique will reveal information on corrosion rate distribution in the tested areas whereas KEMCOP will show information about morphology and adherence of the coating to the substrate.

The next planned outage of boiler 36 in 2011/2012 offers an opportunity to repeat the KEMBUS wall thickness measurements in order to show longer-term performance. The results of these measurements will be of help in selecting the best solution to prolong the intervals between planned outages. The KEMCOM solution has proven to be a valuable tool for minimizing corrosion by optimizing the combustion conditions.

The optimization of the combustion or process conditions can have two separate effects. First, the plant operators can actually see and feel their span of control through the online corrosion measurements. This can lead to their awareness changing from being subconscious, as it often is, to conscious.

In the case of AEB the automated combustion control can be optimized by the conducted online corrosion measurements and can therefore assist the operators. Based on the results of these two routes, the maintenance strategy can be further optimized to ensure the highest throughput at the highest efficiency and the lowest costs.

ACKNOWLEDGEMENTS

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REFERENCES


Innovations in Coal Fired Units:
Coal Injection and Fly Ash Handling

1. INTRODUCTION
Requirements on power plants are generally high when it comes to operational safety, efficiency and environmental protection. Coal fired systems especially, in which fuels and final combustion products in powder form are handled, are of public interest. This paper discusses new possibilities for coal injection, for example those that allow the oxy fuel operation required for economical separation of carbon dioxide (CO₂) from the exhaust gas, and energy-saving and low-wear ash removal systems that revolve around a new type of pneumatic conveying process.

2. NEW COAL DISTRIBUTION AND INJECTION SYSTEM

2.1 SURVEY
The commonly used technique for feeding the burners of a coal fired power plant is the so-called ‘direct injection’ method. Here ground coal is pneumatically conveyed directly from the mill to the burners. One mill feeds several burners simultaneously. The accuracy of distribution to the single burners may deviate by more than ±10 metres % from the rated average value. Boiler load changes intervene in the operation of the mill and are only admissible to a limited extent. The distance between the grinding plant and the burners must be short.

A new distribution and feeding system avoids these limitations. The grinding, preparation and injection of the coal are decoupled by the use of a silo. The coal is transported from this silo pneumatically to a distribution system that comprises a pressure vessel with an integrated distributor, from where groups of burners are fed pneumatically from this, using the transport gas. The pressure in the upper space of the distributor vessel is adjusted to a value that depends on the required burner mass flow.

The coal transport to the distributor is thus decoupled from the transport to the burners, so temporary interruptions of coal feed to the distributor vessel and connection and disconnection of single burners do not affect the throughputs of the active burners.

A single distribution system can feed any number of burners. The pneumatic transport to the burners is a dense-phase form of conveyance. A few metres in front of the single burners the two-phase mixture is adjusted by air injection to achieve the requested solids/gas loading. Figure 1 shows the principle structure of the process.

2.2 FUNCTIONAL PRINCIPLE
The core component of the plant is the distribution vessel with the integrated distributor. Figure 2 shows a schematic representation of its structure. A distributor that is completely open at the top is flanged directly below a pressure vessel with an identically sized outlet opening which serves as a buffer vessel. The basic structure of the distributor is shown in Figure 3 (the distributor of the test plant in the CP Technical Center with four outgoing pipes).

CLICK TO VIEW FIGURE 1:
PRINCIPAL STRUCTURE OF THE COAL PREPARATION AND INJECTION PROCESS

CLICK TO VIEW FIGURE 2:
BASIC STRUCTURE OF THE DISTRIBUTION VESSEL
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Claudius Perea, Projects

Innovations in coal fired units:
- Coal injection and fly ash handling

A. T. M. O. E. T. A.
Association of European Turbine Operators
The pneumatic conveyance from the distribution vessel to the burners is realized as dense phase conveyance. In other words, with loads of $\mu_{\text{cm}} = \frac{M_{\text{cm}}}{V_{\text{cm}}}$ which lie in the range of $\mu_{\text{cm}} = (20 - 50) \text{ kg/kg}$, depending on the selected boundary conditions, and lead to smaller conveying pipe diameters $D_k \leq 125 \text{ mm}$. Since fine-ground coal behaves in accordance with group A of the Geldart diagram [1], a pulsation-free strand conveyance makes an adjustment in the conveying pipe that is supported by the correspondingly high gas retention capacity. The adjustment of the coal/air ratio $P_{\text{air}}$ required or requested for the subsequently connected burner takes place either some metres in front of the respective burner by the admixing of the corresponding air mass flow, $M_{\text{air}}$, via a specially designed annular nozzle. The low pressure level at the point of injection allows for the use of fans for the $M_{\text{air}}$ addition. Load changes of the boiler, in other words changes in the coal mass flow, $M_{\text{cm}}$, are realized by changes in the pressure $p_{\text{cm}}$ in the upper space of the distributor vessel and an adjustment of the air flow $M_{\text{air}}$, to be injected. The conveying gas flow $M_{\text{cm}}$, and thus the condition of the pneumatic conveyance remain unchanged.

In general the system is insensitive to disturbances, allows fast changes of the coal throughput to the burners in a simple manner (change of pressure) and suits integration into a control system well.

A test plant installed in the CF Technical Centre is examined systematically. Different bulk solids and different types of coal with particle size distributions from fine-ground ($d_{50s} = 3.4 \mu m$) to coarse-ground ($d_{50s} = 835 \mu m$) have been tested successfully [2, 3].

2.3 DISTRIBUTION CONTROL

With the injection system discussed it is possible to adjust a uniform coal distribution to the connected burners, as well as a controlled non-uniform distribution. Usually there is a demand for a uniform distribution of the fuel flow, the realization of which this paper will now describe briefly.

The single burner pipes from the distributor to the combustion chamber are usually of different lengths and of different spatial arrangements because of the location of the distributor relative to the combustion chamber. Since at each of these pipe routes the same pressure difference $\Delta P_{\text{gas}}$ acts, the result is different mass flows $M_{\text{cm}}$ through the single pipes. For an even coal distribution these burner pipes must therefore be adjusted to the same resistance length. To this end a calculation programme has been developed.

The burner pipes to the combustion chamber can be treated as the line connection of different pipe elements. These can be straight horizontal and vertical pipe parts, bends with different reversing angles $\alpha$, different ratios of bending radius $R_i$/pipe diameter $D_k$ and different spatial arrangements, and flow control valves in...
different opening positions, for example ball cocks and throttle elements. Changes in pipe diameters along a line are admissible. For all these elements calculation approaches are available that describe the respective correlation of \( \Delta p = \Delta p(M_i) \) [4].

A precondition for the use of these calculation approaches is, however, knowledge of the adjustment parameters for the corresponding bulk solid and the specific operating conditions, such as resistance coefficients, which are used in these equations. In the CP Technical Centre, a pneumatic conveying line has been installed to examine the in-line connection of such components for particular bulk solids under plant-specific operating conditions and to measure the corresponding operating characteristics [3]. Comprehensive data sets are available for different coal types.

The construction elements of the different lance pipes are introduced separately into the calculation programme in the direction of the conveyance and with their characteristic data. The programme carries out a pneumatic conveyance calculation for each line and either determines the corresponding individual pressure losses \( \Delta p_{\text{calc}} \), for the specified single throughputs, \( M_{i,j} \), or the mass flows occurring at a specified value \( \Delta p_{\text{inj}} \). The mass flows can be adjusted to a constant value by definition and installation of compensating elements in any position along the burner pipes. The calculations assume a uniform ratio of solid to air in all burner pipes, in other words, \( \Delta p_{\text{calc}} = M_i/M_{\text{setpoint}} \) constant. The programme described above has worked well in practice.

**CLICK TO VIEW FIGURE 6:**
**BASIC DATA FOR THE CONTROL SYSTEM: A) THE CONVEYING DIAGRAM B) INJECTION CHARACTERISTICS**

In order to adjust the required coal flows \( M_{i,j} = \text{constant}, i = 1 \ldots N \), where \( N \) is the number of connected burners, \( \Sigma M_{i,j} = M_{\text{setpoint}} \). The pressure in the distributor vessel has to be adjusted to the corresponding value \( p_b = (p_b + \Delta p_{\text{inj}}) \), where \( p_b \) is the pressure in the burner chamber or at the burner inlet. The basis for this is in characteristic curve, \( M_{i,j}(\Delta p_{\text{inj}}) \) with \( u_{\text{inj}} = \text{constant} \), which can be taken from the respective conveying diagrams. This is shown by way of example for two characteristic conveying gas velocities \( u_{\text{inj}} \) in Figure 6. Suitable gas velocities, \( u_{\text{inj}} \), lie above the connecting line \( A-A \) in the state diagram (see Figure 6a). For a given conveying route \( \{D_k, L_k\} \) the following general dependency results:

\[
M_{\text{setpoint}} = a \times \frac{\Delta p_{\text{inj}}}{u_{\text{inj}}^2} = k \times \Delta p_{\text{inj}} \quad \Rightarrow \quad k = \frac{a}{u_{\text{inj}}^2}
\]

where \( x \in [0.9-1.4] \) and \( z \in [0.5-1.0] \).

The dependency \( M_{i,j} = k \Delta p_{\text{inj}} \) necessary for a uniform distribution adjustment, can be linearized with high precision via the required \( M_{i,j} \text{ control range} [5] \) (see Figure 6b), as practical experience has shown.

**CLICK TO VIEW FIGURE 7:**
**THE SELF-ADJUSTING CONTROL SYSTEM**

Since most coal types or qualities are used in power plants, for instance due to the purchase of ‘world coal’, the distribution control has been designed as an adaptive self-adjusting system that recognizes changing coal qualities and automatically adjusts to these. This procedure is illustrated schematically in Figure 7. The dependency \( M_{i,j}(\Delta p_{\text{inj}}) \) with gradient \( k_{\text{inj}} \) for a reference coal is given. For the rated mass flow, \( M_{i,j} \), this dependency requires a pressure of \( (p_{\text{distributor}} + \Delta p_{\text{inj}}) \) to the distributor vessel, which will be adjusted. A subsequent measurement of the weight loss of the distributor vessel by means of the installed load cells at interrupted coal feed, however, gives the changed coal mass flow, \( (M_{i,j})_{\text{meas}} = (M_{i,j})_{\text{setpoint}} / N > M_{i,j} \). The system uses equation [1] and the data from the current operation point, i.e., \( \Delta p_{\text{inj}} \), to calculate the gradient \( k_{\text{inj}} \) of the corrected characteristic line \( M_{i,j}(\Delta p_{\text{inj}}) \). On the basis of this new characteristic line the pressure \( (p_{\text{distributor}} + \Delta p_{\text{inj}}) \) in the distributor vessel is adjusted for the setting of the target coal mass flow, \( M_{i,j} \).

For the adjustment of an uneven coal distribution to the burners the distribution vessel can, for instance, be adjusted to the pressure \( p_{\text{distributor}} + \Delta p_{\text{inj}} \) required for the highest single mass flow \( M_{i,j} \).

The individual burner pipes with lower necessary throughputs will then be adjusted to their setpoints by feeding nozzle gas to the inlet of the pipeline (see Figure 2). This means increasing the characteristic gas velocities \( u_{\text{inj}} \) in accordance with equation (1). The further procedure is comparable to that for an even distribution described above. Alternatively it is possible to realize the adjustment by means of valves. In practical operation such uneven distributions are secured by additional absolute measurement of the different mass flows \( M_{i,j} \) or at least by a measurement of the relative throughputs \( \{M_{i,j}/M_{\text{setpoint}}\} \) in the single pipelines which are then converted into absolute values via the measured total mass flow \( M_{\text{setpoint}} \).

2.4 SUMMARY

The sensitivity of the reaction of the pneumatic coal distribution and injection system described here to external obstructions and other interferences during operation is low. It is easy to control and it adjusts itself automatically to different coal types or qualities.

The precision of the distribution to the single burner pipes is high for fine-grained or coarse-grained coals. The respective adjustments are highly reproducible. For even coal distribution, accuracies of \( \pm 3 \) metres % are achieved, referring to the actual setpoint. This allows, among other things, operation of the burners in a controlled manner with clearly lower air excess figures.
This also allows for the use of innovative new techniques for burners or power plants, for example future oxyfuel plants, to reduce CO₂ emissions. Compared with conventional systems, such as direct mill injection, the possible control range of the new system is considerably greater. In addition, the system offers a sound basis for single or group-wise burner control concepts, which will increasingly be in demand in the future.

3. NEW ASH REMOVAL SYSTEM

3.1 SURVEY

A major portion of the incombustible components of coal is separated as fine-grained fly ash in electrostatic precipitators or bag filters. Fly ashes show a group A or group C behaviour according to Geldart [1]. Generally they contain more than 50 metres-% SiO₂ and are thus extremely abrasive.

Collection and removal of the fly ash accumulating in several filter hoppers is generally realized by means of pneumatic conveyance systems. Airslides, multipressure vessels and suction systems with multiple feeding points – in other words, systems with more or less simultaneous feed of fly ash into one transport line via several parallel feeders – are used for this purpose. Economical and operationally safe removal of ash requires the conveying system to have a low construction height, simple and sturdy solid feeders and pneumatic transport with the lowest velocities and simultaneously high loads.

This paper will now discuss the use of an innovative pneumatic dense-phase conveying system in power station ash removal plants. The new FLUIDCON conveying system can be described as a combination of airslide conveying and pneumatic pipe conveying. It combines the advantages of the airslide conveyance which has extremely low energy consumption with those of the pneumatic pipe transport, which has almost unlimited flexibility in the routing of pipes, and eliminates essential disadvantages. Special features of the system are the extremely low transport velocities and very low power consumption.

3.2 THE FLUIDCON CONVEYING PROCESS

Figure 8 shows the structure of the FLUIDCON pipe and Figure 9 the general layout of a conveying plant that uses such a pipe and has a single feed point. The conveying pipe contains an aerating system for fluidizing the bulk material.

The fluidization elements are adjusted in their geometry to the circular conveying pipe cross-section and can be exchanged and dismantled individually without modifications to the conveying pipe. The maximum length of these elements, independently fed with gas, is \( \Delta L = 3 \) metres. For distributing the gas normal airslide fabric is used, if necessary – as in case of fly ash – covered with perforated plate for wear protection. In special cases metal fabric can be used as a distributor. Bends in the conveying line and vertical pipe segments are not fluidized.

The total gas flow \( M_g \) supplied by the pressure generator is divided into a fluidizing gas flow \( M_{g,fl} \) and a driving gas flow \( M_{g,dr} \). The fluidizing gas flow \( M_{g,fl} \) is adjusted by a flow controller to a given target and is fed to the conveying pipe, distributed along the transport route, for fluidization of the bulk material. The driving gas flow \( M_{g,dr} \) is introduced at the beginning of the conveying pipe and triggers the axial transport of solids. Here the pressure drop of \( M_{g,dr} \) replaces the slope of the airslide that provides the driving force in an airslide.

Because the fluidization the bulk solid is transferred into a fluid-like state with almost no internal friction and is lifted off the pipe bottom and introduced into the driving gas flow. It therefore does not support itself on the (horizontal) pipe wall. These are optimum conveying conditions for the realization of the same conveying velocities as on an airslide.

The operating conditions for FLUIDCON plants include typical gas velocities at the start of the conveying pipe are in the range of \( u_{b,ini} = (1–3) \) m/s and the specific fluidizing gas flows in the range of \( q_{g,fl} = (0.3–1.0) \) m³/(m² · min). The low conveying pressures required for fluidized conveyance mean that the gas supply can often be provided by blowers \( \Delta p_p \leq 1.0 \) bar. Small conveying pressure differences, \( \Delta p_p \), have the additional effect of reducing the increase in gas velocity caused by the gas expansion. The result is that the airslide character of the flow is also maintained for longer without stepwise enlargement of the pipeline. The aim is to achieve final gas velocities in the range of \( u_{ini} = (7–12) \) m/s.

Suitable and proven solid feeders for FLUIDCON are pressure vessels, screw feeders, rotary-valve feeders and various flap-type feeders. Conveying pressures of up to 3 bar(g) are possible. Experience from operating plants shows that the power consumption of a FLUIDCON plant is only about 50 per cent of that of an energy-optimized conventional dense-phase pneumatic conveying system.

With FLUIDCON it is possible to convey bulk solids along an upward incline, a situation that should be avoided in the case of conventional pneumatic conveying systems because of the risk of backflow. To date angles of up to \( \alpha_2 \approx 30^\circ \) have been tested and implemented.

The re-starting of conveying after, for example, an interruption by a power failure, in other words, starting up against a full line, is not
a problem for FLUIDCON. The conveying gas is supplied to the conveying system with staggered timing. After the introduction of the fluidizing gas the driving gas flow is switched on after a short time delay. This picks up the bulk material that has already been transformed into a fluidized state and carries it away evenly and without significant pressure fluctuations. The original steady-state conveying situation is restored after less than a minute. This procedure has proven successful with all bulk materials investigated so far, and is implemented as standard in FLUIDCON plants. The bulk materials that are particularly suitable for FLUIDCON are all those that can be fluidized with low gas velocities and which then expand homogeneously. Long gas retention is also of advantage. Bulk materials with appropriate characteristics are to be found in the entire hatched part of the Geldart diagram shown in Figure 10.

CLICK TO VIEW FIGURE 10:
SUITABLE BULK SOLIDS

The suitability of products outside the hatched area has to be analyzed for each individual case by fluidization and various other tests. All bulk materials plotted in Figure 10 have already been transported successfully with FLUIDCON. Fly ashes from different sources are included. The dimensioning of FLUIDCON plants is based on systematic conveying trials on test plants that are suitable for scalings up. The results are then incorporated in an appropriate computational model. These investigations are carried out on two conveying routes in the CP Technical Center: one with a nominal pipe diameter \( D_0 = 100 \) mm and a length \( L_0 = 150 \) metres, a second one with the dimensions \( D_0 = 150 \) mm, \( L_0 = 55 \) metres) for the purposes of scaling up.

The operating experiences of around 75 FLUIDCON plants for the transport of different types of bulk solids are considered in the calculation model. Supplementary information on the method, design and operating experience can be found in [6, 7].

3.3 USE UNDER POWER STATION FILTERS

FLUIDCON is particularly suitable for multipoint feeding. Fly ash collected in various filter hoppers is fed into a common delivery line that links a large number of these hoppers. The bulk material in its fluidized state reacts almost instantaneously to disperse any accumulation or compaction of material underneath the feed points and along the conveying line. This process is accompanied by short, very moderate, conveying pressure peaks at the start of the pipeline. The high loadings, \( \mu \) that can be achieved with FLUIDCON combined with a low conveying pressure, \( \Delta p_{\text{m}} \), permit the use of simple, inexpensive, feeder systems such as rotary valves and double flap valves. This is very important because there is a large number of feed points under a power station filter.

Figure 11 shows a section from the flow sheet of an electrostatic precipitator ash removal system with FLUIDCON conveyance. Here the fly ash is transported off into the flow direction of the flue gas. The advantage is that the conveying system is first fed with the coarse-grained fly ash from the first field, onto which is then placed the far more fine-grained and thus generally extremely cohesive ash of the subsequent cleaning. This improves the conveyability of this ash considerably.

CLICK TO VIEW FIGURE 11:
PRINCIPAL STRUCTURE OF A FLUIDCON ASH REMOVAL SYSTEM

Feeder are installed in the front fields of the filter rotary whereas in the rear area time-controlled double pendulum flaps are arranged because of the very small ash quantities accumulating there. The construction height of the conveying system is so low that an expensive elevation of the filter is not necessary. Outside the filter the conveying route can be inclined uphill. This means that the construction height required, for example, for intermediate bins can be achieved. The collecting pipes below the single filter rows feed a common FLUIDCON conveyor pipe in parallel and simultaneously. That pipe then transports the fly ash to its destination, usually the storage silos.

In the case of gas cleaning by means of fabric filters the accumulation of the separated fly ash over the width and the length of the filter is even with regard to quantity and grain size. This allows for further system variants, for example ash collection across the flue gas path.

For technical and economic reasons the use of rotary feeders limits conveying distance. With a given throughput \( M_0 \) and a constant pipe diameter \( D_0 \) an increasing conveying distance \( L_0 \) leads to an increasing conveying pressure difference \( \Delta p_{\text{m}} \). This is also acting on the rotary feeders, thus increasing their chamber gas losses and leakage gas losses and resulting in increased wear strain on the feeders.

The installed pressure generator has to supply the actual conveying gas flow and the increasing leakage gas flows at ever increasing pressure. The pressure increase can be counteracted by enlarging the pipe diameter \( D_0 \) which again, however, increases the required conveying gas flow. The conclusion is that economical conveying distances of FLUIDCON ash removal systems with rotary feeders are limited to \( L_0 = 300 \) metres. For distances of \( L_0 > 300 \) metres other solids feeders and/or conveyances with intermediate stations are required.

Various factors can necessitate a combination of solutions. These are the requirement profile determined by different filter systems, constructional situations at the site, long conveying distances and, in particular, changing coal and ash qualities.
One such situation is collection of fly ash below the filter with minimum energy consumption by means of low-cost airslides which discharge the ash via rotary feeders directly into a joint FLUIDCON conveyor pipe for further transport to the storage silos. When conveying distances are extremely long the FLUIDCON conveyance, which is decoupled from the ash transport under the filter by an intermediate bin, can be equipped with a solids feeder that is suitable for the distance. This could be a pressure vessel or screw feeder.

The FLUIDCON system has been successfully implemented for ash removal in power stations fired with hard coal and brown coal. One example is the ash removal from two electrostatic precipitators in a power station fired by brown coal. Here, $M_t \approx 55$ tonnes/hour of lignite fly ash at each filter from 18 parallel collection points is transported in a common FLUIDCON pipeline.

### 3.4 SUMMARY

This paper has presented the application of a new pneumatic dense-phase conveying system for power station ash removal. The FLUIDCON process combines the advantages of airslide conveyance with those of pneumatic pipe conveyance. Its characteristic features are low-energy consumption and low transport velocities.

Since the required pressure loss is generally low, simple solids feeders such as rotary valves or double flap valves can be used. The high number of ash accumulation points under power station filters and the very small construction height of the conveying system – which means no elevation of the filter is necessary – minimizes investment costs. The low conveying velocities reduce pipe wear considerably.
REFERENCES

Advanced SNCR technology for Coal Fired Boilers of 200 MWe, in Germany, and 225 MWe, in Poland

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INTRODUCTION
In Western Europe the retrofitting of large coal fired boilers with nitrogen oxides (NOx) control systems was concluded years ago. Since the selective catalytic reduction process (SCR) was considered the best available technology (BAT) in the 1980s and 1990s, most boilers today are equipped with it.

From the 1990s a number of Eastern European countries joined the EU and as a consequence they had to accept new emission limits. This meant that most of their power plants’ existing boilers had either to shut down or measures had to be taken to follow stringent regulations on the control of emissions such as NOx.

Reliable results from and experience in SCR technology – which might be the technology of first choice – are available to help estimate to a high degree of accuracy the technology’s feasibility and its investment and operating costs. However, the investment costs for SCR technology are about ten times higher than for a selective non-catalytic reduction (SNCR) system, and it has other disadvantages too:

- Installation of the catalyst is often critical, especially when the boiler has a large economiser instead of an air preheater. This means that heat exchangers would have to be replaced to accommodate the catalyst
- The height of most boilers, accommodation of the weight of the catalyst and the steel structure would generally cause the problem of static
- The pressure drop could make the operating costs for an SCR system higher than those for an SNCR system and the investment could amount to multiples of that in an SNCR system
- The downtime of the boiler for retrofitting with SCR could result in considerable loss of profit

The SNCR process has been continuously improved for use with small boilers, such as those in waste incineration plants, especially in recent years, and is widely considered now as BAT for this size. With this in mind an increasing number of owners of power plants are now seriously investigating whether the SNCR process is feasible for their large boilers too. Besides performance, they are generally paying special attention to the overall cost compared with SCR.

This paper describes tests on SNCR demonstration plants in two large coal fired boilers and their results. One plant is in Germany, the other in Poland.

GENERAL INFORMATION
In the SNCR process, reductants in aqueous solution (ammonia water or urea) or in gaseous form (ammonia, NH₃) are injected into hot flue gases. Molecular nitrogen (N₂), water vapour (H₂O) and carbon dioxide (CO₂) are formed as the reaction products.

Both urea solution and ammonia water can be used for NOx reduction in combustion plants. Depending on the application both reductants have specific advantages and disadvantages. For optimum NOx reduction with minimum NH₃ slip it is only necessary to evenly distribute and thoroughly mix the reductant in the flue gases within the appropriate temperature window in which NOx reduction is possible.

The optimum temperature range to achieve simultaneously high NOx reduction, minimum consumption of reductant and low NH₃ slip is narrow and mainly depends on the flue gas composition (see Figure 1). For coal fired boilers the optimum temperature lies in the range 960–1020 °C.

Since the temperatures over the cross-section in the furnace are rarely uniform and as considerable imbalances are often measured, special measures need to be taken to identify the correct positions for the injectors.
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was selected by the Best Paper Awards Committee as one of the three finalists for the conference paper entitled

Advanced SNCR Technology for coal fired boilers - 200 MWel in Germany and 225 MWel in Poland

with TRACK & COAL-FIRED BIOMASS COMBUSTION AND WASTE TO ENERGY

[Signature]
and distribute the reductant properly into the flue gas under all operating conditions.

**CLICK TO VIEW FIGURE 1: NOX REDUCTION AS A FUNCTION OF TEMPERATURE**

**TEMPERATURE MEASUREMENTS**
To get an idea about whether the SNCR process would suit the boilers in Germany and Poland, the first step to take was to determine realistic values for temperatures at the potential positions for reductant injection.

Since temperatures measured with thermocouples, which are usually installed in the boiler walls, are affected by the influence of radiation from flames and boiler walls, a suction pyrometer was used. It consists of a water-cooled lance with an NiCrNi thermocouple on its tip, which is protected by a ceramic shield. The hot flue gases are sucked into the lance in such a way that the real gas temperature can be measured. The negative pressure required is generated by an ejector with compressed air. To avoid new openings and save costs, the only openings used at both boilers were those already available for inspection or thermocouples. Despite inaccuracies the conclusion to be drawn from the results of the temperature measurements was that the required NOx reduction could be achieved with the SNCR process with a high probability of success in both boilers.

However, to determine whether these values can also be guaranteed under changing operating conditions and boiler loads, and to work out what kind of design and equipment the commercial SNCR plant will comprise, the decision was taken to perform so-called tentative tests using a temporary test installation.

**DEMONSTRATION PLANT (TEST PLANT)**
To minimize technical effort and the cost of tests, we accepted the tentative tests using a temporary test installation.

Since temperatures measured with thermocouples, which are usually installed in the boiler walls, are affected by the influence of radiation from flames and boiler walls, a suction pyrometer was used. It consists of a water-cooled lance with an NiCrNi thermocouple on its tip, which is protected by a ceramic shield. The hot flue gases are sucked into the lance in such a way that the real gas temperature can be measured. The negative pressure required is generated by an ejector with compressed air. To avoid new openings and save costs, the only openings used at both boilers were those already available for inspection or thermocouples. Despite inaccuracies the conclusion to be drawn from the results of the temperature measurements was that the required NOx reduction could be achieved with the SNCR process with a high probability of success in both boilers.

To make sure that the reductant was injected into a less favourable temperature. Moreover, the reason being that urea solution is much easier to handle than ammonia water, so it did not make sense to use ammonia water during the short duration of the test.

From the point of view of performance, both reductants are comparable so the test results provide reliable information for a commercial plant regardless of whether the reductant is urea solution or ammonia water.

Table 1 lists the limitations the tests faced at both locations.

**CLICK TO VIEW FIGURE 3: TEMPORARY INSTALLATION OF INJECTOR**

**TESTS AT THE 200 MW POWER PLANT IN GERMANY**
A power plant in Germany is operating a coal fired boiler of 200 MW at loads of 20–100 per cent. The beginning of the tests soon showed that the number and size of openings were not sufficient to achieve adequate penetration into the flue gas, so the distribution of the reductant in the cross-section of the boiler was not homogeneous. Therefore the results of the first tests were not satisfactory and the plant was modified step-by-step as the tests progressed.

Alternating injection from the right and left sides of the boiler showed that the NOx reduction on the left was only one third of what was achieved on the right side under operating conditions that were otherwise equal. Obviously the reason was that on the left side the reductant was injected into a less favourable temperature.

With an improved configuration of the plant and the injection of the reductant in more suitable temperatures, the required NOx reductions of greater than 130 mg/Nm³ were obtained in all load ranges. Even the simple means available for performing the tests allowed the desired NOx reduction to be reached in the tested load ranges. This showed that an optimally designed commercial plant can safely achieve or exceed the required NOx clean gas values (see Figure 4).

**CLICK TO VIEW TABLE 1: TRIAL LIMITATIONS**

**CLICK TO VIEW FIGURE 2: DEMONSTRATION PLANT: METERING AND MIXING MODULE, PUMPING MODULE AND STORAGE CONTAINER FOR NOXAMID40**

Modifications to the boilers were restricted to what was absolutely necessary. For instance, we avoided the expensive and time-consuming bending of tubes in the boiler walls to accommodate injection lances. We provided holes of diameter only about 10 mm for the injectors. These holes were in the fins between the boiler tubes (see Figure 3). Injection lances were also not installed in boiler areas where access is difficult. It was clear from the beginning that an optimum penetration and distribution of the reagent over the whole cross-section of the furnace could not be expected.

**CLICK TO VIEW FIGURE 4: CONFIGURATION OF INJECTION LEVELS AND METERING AND MIXING AND DISTRIBUTION MODULES**

Compared with the demonstration plant a commercial plant designed for its application will provide better results for these reasons:
The SNCR process has proven itself in long-term continuous operation in various combustion plants to be a reliable and economical process for reducing NOx to meet required NOx limits. Tests at these power plants met all expectations and mostly surpassed them.

The SNCR plant can respond more quickly to changing operating conditions since it involves automatic control rather than the manual changing of injection lances.

The boiler includes openings for injection lances. These openings allow the optimum distribution of the reductant. Instead of being injected from two sides, the fluid can be injected from four sides at the 45-metre level and from three sides at the 48-metre level. At the 51-metre level, where the temperatures near the boiler wall would be too low even under full load, longer lances are used to inject the reductant into the hot centre.

Acoustic temperature measurement determines the temperature profile across the entire cross-section of the combustion chamber so that individual lances may be controlled according to the temperature. This allows each lance to inject the reductant into the optimum temperature. This yields higher NOx reduction, decreases the NH3 slip and lowers the reductant consumption required.

The owner of the power plant has investigated the feasibility of retrofitting with SCR. The aim is to give it a reliable basis on which to make a decision about which process to choose. On consideration of all relevant factors, such as the degree of NOx reduction, the cost-benefit ratio and availability, SNCR technology comes out as the best option available today for the boiler under investigation. When the results became available, the owner decided, in principle, to install a commercial SNCR system instead of an SCR type.

The temperature measurements performed before the tests using suction pyrometers and the readings from the permanently installed thermocouples only allow rough assumptions to be made about the temperatures at the individual injection levels under potential boiler loads. Beyond these assumptions the temperature distribution and imbalances resulting from factors such as the boiler load and the ignition behaviour mean that the burner configuration may be very different. Moreover the temperature window moves further up the combustion chamber in the course of operation because of the increasing degree of contamination of the heating surfaces. Depending on the fuel type, fuel distribution and air supply, temperature imbalances of up to 150 °C – and sometimes higher – are typical.

The flue gas temperatures, measured with thermocouples and averaged, can be used as reference temperatures to a limited extent. But these averages say nothing about the temperature profile or the imbalances at the injection levels. Moreover radiation from the furnace walls affects the measurements, resulting in deviations from real flue gas temperatures of 60–100 K. In addition, deposits on thermocouples lead to an increasing isolation effect over the course of operation, hence temperature measurements of the process control system are time-delayed by 10 minutes and longer depending on the thickness of such deposits.

To ensure that the reductant is always injected in the upper range of the temperature window under all possible operation conditions, in other words, in the range where the NOx reduction is highest and the NH3 slip lowest, acoustic gas temperature measurement (AGAM) systems are provided in plants where high performance is required. AGAM measures the real gas temperatures near the injection points and determines the temperature profiles across the entire combustion chamber cross-section.

The system consists of two parts. Firstly, transmitter and receiver units of an identical mechanical and electrical design that are mounted on the walls of the combustion chamber, and secondly, an external control unit (see Figure 5). During the measurement the solenoid valve in the compressed air line on the transmitter side is opened, generating acoustic signals.

The signals are recorded simultaneously on the transmitter side and on the receiver side. The digitized signals are used to measure the transmission time. As the distance is known, the sound velocity can be determined, which is then converted into a temperature, the so-called ‘path temperature’. The use of several combined transmitter–receiver units acting at one level provides multiple path configurations that determine the two-dimensional temperature distribution at that level in real time.

The temperature profile determined is divided into sections. The sections can be assigned to individual lances or groups of lances, which can be switched to other levels depending on the flue gas temperature measured. This ensures that the reductant gets to the locations that are best for the reaction, even at rapidly varying flue gas temperatures. It also ensures that the SNCR plant is always operated in the optimum temperature range for the degree of NOx reduction, NH3 slip and reductant consumption required (see Figure 6).

The basic decision had been made in favour of the SNCR process, an AGAM system was installed some time before the placement of the order for the commercial SNCR. The aim was to obtain as much detailed information as possible and ensure...
maximum certainty for the engineering of the commercial SNCR plant, in particular regarding the configuration and confirmation of the SNCR injection levels and positions.

The temperature measurements were performed at the end of the combustion chamber, or at 39 metres, with different loads and configurations of pulverizer. The positions of the AGAM measurement level and the burner levels are shown in Figure 7, which also shows the arrangement of the eight transmitter and receiver units and the paths of the acoustic measurement. On the basis of the 24 measured path values the temperature distribution, or arrangement of isotherms, is calculated tomographically.

CLICK TO VIEW FIGURE 7:
BOILER WITH FIVE INJECTION LEVELS AND AGAM

Four symmetric temperature zones are determined from the temperature matrix. The surface average value is used to calculate deviations in the zones. The monitor of the acoustic diagnostic computer displays the isotherms, the configuration of the 16 zones with indication of the deviations from the average value, as well as the zone or surface average value (see Figure 8).

CLICK TO VIEW FIGURE 8:
CONFIGURATION OF 16 TEMPERATURE ZONES UNDER AGAM

The colour in each zone changes from green to red or blue if the deviation from the average value exceeds 25 K or is lower than –25 K. Under the zone or isotherm diagram the four zone deviations from the average value are shown as trends. The average temperature at the end of the combustion chamber varies between 750 °C under low load (45 MW, burner level 1) and 1155 °C under full load (185 MW, with all burners in operation), as Figure 9 indicates.

CLICK TO VIEW FIGURE 9:
TEMPERATURE PROFILES IN AGAM MEASUREMENT LEVEL AT DIFFERENT BOILER LOAD CONFIGURATIONS

The following engineering concept was determined on the basis of the analyses of temperature measurements and the tests with the SNCR demonstration plant.

SNCR PLANT TECHNICAL CONCEPT

The simplified process flow chart (see Figure 10) shows the function and the scope of supply of the commercial SNCR plant as planned and implemented in the power plant. Due to the major temperature differences between low load (20 per cent) and full load as well as the extreme temperature imbalances, there are five injection levels, from 26–51.8 metres.

CLICK TO VIEW FIGURE 10:
FLOW DIAGRAM OF SNCR WITH FIVE INJECTION LEVELS AND AGAM

The injectors are arranged in such a way that the right and the left sides of the boiler can be controlled independently of each other. Each injection lance may be individually activated or deactivated. The SNCR plant in its final stage consists mainly of the key components described below. More sophisticated design and implementation requirements are to be considered for operation with ammonia water rather than urea solution because safety requirements are more stringent.

(I) REDUCTANT STORAGE AND SUPPLY

Ammonia water, which is used as a reductant, is mixed at the power plant site by using pressure liquefied NH₃, used in the SCR plants installed at the other boilers, and is pumped through a pipeline to a stainless steel storage tank. Alternatively, filling from tank trucks is possible. NH₃ vapours leaking from the storage tank are absorbed in a tank filled with water and returned to the storage tank when a certain concentration of NH₃ is reached. This means that a gas exchange pipe is not required.

The comprehensive safety equipment at the plant includes NH₃ sensors, flame arresters, full-body and eye showers, and wind direction indicators.

Ammonia water is classified under water hazard class 2 (dangerous to water) and falls under the European standard EN 12952-14:2004 (formerly TRD 451 and 452) because of its high potential for harming the environment. When handling ammonia water a distinction to water) and falls under the European standard EN 12952-14:2004 (formerly TRD 451 and 452) because of its high potential for harming the environment. When handling ammonia water a distinction must be made between ammonia water in the tank and pipes and gaseous NH₃ after vaporization above the liquid in the tank and that which may leak. Therefore the particular hazard potentials of both dissolved and gaseous NH₃ need to be considered.

(ii) TRANSFER PUMPS

From the storage tank the reductants are pumped directly back into the tank via a recirculation line and a pressure retaining valve. A line branches from this ring line and leads to the two mixing and measuring modules. Control valves supply the amount of reductant required for denitrification, whereas the excess ammonia water is returned to the tank.

Using submersible pumps to convey the ammonia water from the tank to the injection lances is not permitted. Although they are less costly they involve a risk of explosion. The SNCR plant uses leak-free magnetically coupled pumps.

Insulation and heating of the tank and pipes are not required since the NH₃ content lowers the freezing point of water and crystallization of NH₃ is not possible. The freezing point of 25 per cent ammonia water, for example, is -57 °C.
[III] MIXING AND MEASURING MODULES
The mixing and measuring modules mainly serve to:

- measure all flow rates (reductant, water, air)
- mix the reductant with process water
- interrupt the reductant supply in case of trouble during operation

Because of the number of injection levels and injectors, two distribution modules were installed on each of the five injection levels to distribute the liquids and the atomizing air to the injection lances. All modules contain the armatures and measuring and control instruments necessary for operation at the flow rates and pressures that the reductants, compressed air and process water require (see Figure 11).

CLICK TO VIEW FIGURE 11:
METERING AND MIXING MODULE AND DISTRIBUTION MODULE

The pressure of the liquids and the compressed air depends on the required penetration into the boiler and the droplet size. It is usually 3.5–4 bar at the inlet of the injection lances, resulting in a pressure of about 4–4.5 bar at the pressure reducing valve at the inlet of the mixing and metering module. This takes into account the pressure loss inside the module and the pipes to the lances.

All components of the modules are mounted on a base-frame. To protect the instruments, especially against dust and splashing water, the module is housed in a cabinet. Glass doors are provided to make it easier to take readings and even facilitate readings just by passing by it. In plants that use ammonia water, glass doors help minimize the hazard potential for maintenance staff since any leaks can be identified without opening the doors and exposing the staff to toxic vapours.

Regulations regarding mixing and measuring modules operated with ammonia water are more stringent than those applied to urea solution. As a minimum requirement pipes and fittings must be provided with pressure rating PN10. A rating of higher pressure, as sometimes required by some operators, is not recommended since this would also require measuring instruments, such as manometers, to have higher measuring ranges and scales and would thus affect the accuracy of readings. All fittings and materials require 3.1 certificates. To prevent hazards from leakage, NH₃ detectors are provided to trigger an alarm at 400 ppm of NH₃ and switch off the pumps at 800 ppm.

[IV] INJECTION SYSTEM
To ensure optimum NOx reduction, nozzles are used that are designed to generate the correct size and velocity of droplet for the boiler geometry and flue gas conditions. Each injection lance is provided with one or more nozzles to ensure an even distribution of the water-solved reductant in the flue gas. For ease of handling, compressed air instead of steam is used as a driving agent in the German power plant. However, both agents are suitable from the process point of view. For the area containing reductant NOxAMID, normal process water can be used as the dilutant and serves as the carrier medium.

Since NOxAMID contains special additives that prevent the precipitation of lime, soft water is not necessary. However, demineralized water or demineralized water is mandatory for ammonia water, otherwise lime deposits may cause fittings and nozzles to clog, sometimes within a day.

The mixture of ammonia water and demineralized water is injected by means of lances in the walls. This prevents the hot and aggressive flue gases from corroding the lances.

(V) PROCESS CONTROL
Simultaneous measurement of the NOx content of the raw and clean gas is not possible in the SNCR process. Measurements are performed in the colder flue gas downstream of the boiler, so the NOx content can only be measured alternately with or without reductant injection.

This is because there is a time delay between injection into the combustion chamber and the NOx measurement in the stack, the sampling and the analysis, and because of the distance between the lances and the newly set concentration of the reductant at the control valve. The reductant volume for a specific boiler load needs to be calculated roughly, as quickly as possible and in advance, to respond to changing operating conditions.

This is effected by means of a load signal, the defined NOx clean gas value and the resulting NOx charge. The volume is continuously corrected depending on the measured actual NOx clean gas value. To avoid extreme variations in the reductant volumes, a constant base volume is preselected that depends on the expected mode of operation. This serves as the minimum limit value for the reductant volume. SNCR plants in general are switched on and the injection levels or, as in this SNCR plant, individual lances are changed depending on the combustion chamber temperature in the sections determined through the use of the acoustic temperature measurement system.

These sections have been allocated to individual lances. The process is controlled via a stand-alone PLC but may also be controlled via the process control system of the overall plant. Visualization is effected by a bus connection to the control room. This is common practice, especially in large combustion plants.

NH₃ SLIP
NH₃ may form ammonia salts if SO₂ or HCl, or both are in the flue gas. These salts may have a considerable impact on the operation and availability of the systems downstream in the plant.
This may hold true for plants with high SO₂ and low-dust concentrations, such as systems fired by heavy oil. However, such contemplations often do not consider that SCR processes partially face much bigger problems with such fuels because of high SO₂ and vanadium pentoxide concentrations.

SO₂ reacts with the NH₃ injected for reducing NOₓ in the catalyst and forms ammonium salts that form deposits of fine dust. Moreover vanadium pentoxide increases the reactivity of the catalyst, which increases the conversion rate of SO₂ into SO₃ and causes the formation of sulphuric acid and related problems of corrosion. Opinion holds that the formation of ammonium salts in coal fired boilers that occurs because of the NH₃ slip in SNCR plants causes technical problems, such as deposits of ammonium hydrogen sulphate in the heat exchangers and consequent losses in pressure, but this seldom happens.

Ammonium hydrogen sulphate mainly accumulates in the fly ash and is separated out in the filter, if the plant concept is appropriate, even the loading of the fly ash and the by-products from flue gas cleaning will be held within acceptable limits. In special cases a small catalyst disc may be installed at the boiler end, with little effort, to limit NH₃ slip and achieve additional NOₓ separation.

**AVAILABILITY OF SNCR**

SNCR systems have virtually no effect on the overall availability of the plant. Availability values of 98 per cent or 99 per cent can generally be guaranteed. There is redundancy in all components that are critical for plant operation and that can affect the availability of the plant, such as pumps.

The injection lances in contact with the flue gas, which need to be regularly checked and serviced because they are wearing parts, may be conveniently checked during operation and replaced in good time if necessary. To avoid jeopardizing the NOₓ half-hourly means, individual lances should be replaced one after another. Used lances may be reconditioned by cutting or replacing the protection pipes. Occasionally the nozzles also need to be replaced.

The installed armatures are usually designed for long-term operation so do not need to be replaced during operation if the SNCR plant is regularly maintained during scheduled shutdowns of the overall plant.

However, if unexpected damage occurs, most problems, such as the replacement of flow meters and manometers, may be corrected during operation. Control valves might be more critical. However, each has a bypass so that the relevant flow rates of the reductant can be manually adjusted until the valve has been replaced or repaired.

Predictive spare part storage and regular maintenance during scheduled plant shutdowns will minimize all problems during operation, if not avoid them all together. If, however, an unscheduled shutdown of the SNCR plant becomes necessary, problems may be corrected within a short period. The daily mean values will not be at risk.

Lime deposits in the piping system, including armatures and injection lances, can only be avoided if urea solutions with a suitable additive are used, for example NOxA MD.

If the SNCR plant is operated with ammonia water as a reductant, it is mandatory to use demineralized or de-ionized water as the diluant. The removal of lime deposits is a time-consuming procedure and may have a considerable impact on the availability of the overall plant.

The plant in Germany has an automatic data acquisition system to allow fault diagnosis and settings via telephone. The higher investment cost of such a system will amortize in a short time because its use avoids the need for costly visits by service engineers.

**SNCR DEMONSTRATION IN A 225 MW PLANT IN POLAND**

A power plant in Poland has five coal fired boilers with a capacity of 225 MWe each. The objective of the SNCR demonstration here was to provide reliable information about whether NOₓ reductions of at least 25 per cent can be safely achieved at boiler loads of 40–100 per cent.

Temperature measurements were only able to be taken at two openings at 47.4 metres. These showed that there are temperature imbalances of more than 120 K between the measuring points. Further measurements were not possible because there were no more openings large enough to accommodate the pyrometer lance. The urea was injected during the tests through openings at 37.9 metres and 47.4 metres in the front wall, and at 47.4 metres in the side walls (see Figure 12).
held to a low enough level to keep the NH$_3$ concentration in the fly ash below an acceptable limit. This would avoid the need for an additional catalyst slice. In samples taken from the fly ash, NH$_3$ content was found to be 40–80 mg/kg fly ash.

**OPERATING RESULTS WITH A COMMERCIAL SNCR IN A 200 MW COAL FIRED PLANT**

The SNCR plant began operating in March 2010. The guaranteed NOx and NH$_3$ clean gas values were instantly reached at most boiler loads between 20 per cent and 100 per cent. The subsequent optimization phase was time-consuming because in each of the five injecting levels the temperature profile had to be measured at various loads with suction pyrometers in order to calculate variances from the temperatures measured with the AGAM.

This was necessary to determine which lance should be operated according to the average temperatures in the zones and at which temperatures the switching should occur for different loads. The settings for pressure and flow rate of the ammonia water, demineralized water and compressed air also had to be adapted to operating conditions.

The principle of the operation of the SNCR according to the temperature profiles established with the AGAM is illustrated on the display of the control system (see Figure 13). The level of NOx reduction and the quick reaction after injection of ammonia water can be seen in Figure 14.

**SUMMARY AND OUTLOOK**

The SNCR process has proven itself in long-term continuous operation in various combustion plants to be a reliable and economical process for reducing NOx to meet required NOx limits. Tests at these power plants met all expectations and mostly surpassed them.

From the point of view of the process it is of virtually no relevance whether urea solution or ammonia water is used as a reductant. If plants are engineered, installed and operated in an appropriate manner, neither medium is expected to have an impact on the availability of the overall plant.

Although SCR technology allows slightly higher NOx reduction levels to be achieved than SNCR technology does, the cost-benefit ratio is seldom good. This is especially true when we considering that NOx values of 350 mg/Nm$^3$ or lower are often obtained through combustion modifications alone. During the decision-making process one consideration that should be made is that the level of environmental protection as defined by BAT is not achieved. This is because the investment costs for an SCR plant alone, for instance, are so high that five to ten SNCR plants could be built for the same amount.

Each would be able to ensure compliance with future NOx regulations. Together they would reduce power generation’s impact on the environment and lower costs for owners compared with one SCR plant alone.

We have experience with urea and ammonia water and hence are able to offer and implement customized proposals for a cost-effective solution of the NOx problem, thus complying with, and in many cases exceeding, the legal requirements of large combustion plants.

Test results from other combustion plants with an electricity output of up to 225 MW are promising. In Poland and the Czech Republic the first decisions in favour of SNCR technology for large power plants are expected to be taken in 2010.
REFERENCES


Repair of Damage Caused by Thermal Expansion of Generator End Windings Support Saves Time and Costs

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ABSTRACT
To avoid the damage that can be caused by hindered thermal relative movements of the stator bars in relation to the adjacent components with different thermal properties, Sensoplan has developed and patented a highly efficient repair method. This results in savings of both time and money.

In certain series of air and H2-cooled generators, the lack of the end winding support system blocks the necessary thermal relative movements of the stator bars – as a result, overstressing leads to detrimental effects such as cracked welds, broken contact faces and wear at main insulation. Damage is found on baseload generators, as well as at medium load and peak load machines. Wear typically starts slowly – visible as white dust - before it accelerates exponentially at a later stage.

Without preemptive measures this can cause the need for a stator rewind after relatively short operating time. The analysis of the damage at some generators led to systematic causes resulting in the development of the patented Sensoplan TET™-Design. This repair package upgrades the stator end winding support system by introducing structural flexibility with an innovative modification concept, individually designed for each machine. The upgrade recovers the space required for all thermal movements of the stator bars.

The financial and time benefit is that the modification is performed in-situ without rewind or the costly outages that result from the time taken in rewinds. The paper illustrates the phenomenon of thermal blocking of stator bars for certain generator series, and the mechanism of the patented Sensoplan TET-Design, which can be considered as a highly efficient repair method. As an example, the project of the 880 MVA Scholven Generator Unit F of E.ON Kraftwerke GmbH will be presented including latest news about the operating experiences with TET.

1. INTRODUCTION
This paper describes the phenomenon of the thermal blocking of stator bars and the mechanism of the patented highly efficient and operationally proven repair method called Sensoplan Trapezium Enhanced Technology Design (TETDesign).

In certain series of air and H2-cooled generators, the end winding support system blocks the thermal relative movements of the stator bars. As a consequence overstressing leads to detrimental effects, such as cracked welds, broken contact faces and wear at the main insulation. Damage is found on baseload generators as well, as medium load and peak load machines.

Wear typically starts slowly – visible as white dust – before it accelerates exponentially at a later stage. Without preemptive measures it is not possible to avoid the stator rewind, which frequently occurs only after a short operating time.

Analysis of generators has led to the identification of the systematic cause of the damage and has resulted in the development of the patented Sensoplan TET-Design. This repair package upgrades the stator end winding support system by introducing structural flexibility for all thermal movements of the stator bars. It employs an innovative modification, individually designed for each machine. The benefit in money and time is that the modification is performed in-situ without rewinding, which would require a costly and time-consuming outage.

This paper presents an example repair project, that of the 880 MVA Scholven Generator Unit F of E.ON Kraftwerke GmbH, which has one year of field experience with the successfully implemented Sensoplan TET-Design.

2. FINDINGS
In certain series of inner and outer-cooled generators that use air or H2, a stiff support system for the end winding prevents the necessary thermal relative movements of the stator bars. The resulting overstressing leads to detrimental effects, such as broken contact faces, wear at the main insulation and even cracked welds. Typical wear patterns are shown in Figure 1.
Thorsten Wasmuth accepted the award on behalf of Günter Ebi.
White dust is predominantly found at the tied connections between the lower bars and the outer support ring near the end caps and between the lower bars and the trapezoidal support plates. What all findings have in common is that the amount of dust progressively increases from the slot exit towards the bar ends.

Typically there is little or no dust on the first two to three tied connections of the lower bar following the slot exit while there is a lot of dust at the last tied connection to the outer support ring. White dust consists of pulverized epoxy resin and develops as a result of relative frictional movements between the bar main insulation and the tie, between the tie and the support plate or ring, or between individual tie strings.

In units that are contaminated with oil leaking from seal oil or bearing oil systems the combination of oil film and dust creates a substance that looks like grease. Although the appearance and colour of this material is different to that of the white dust, its cause is the same: the relative movement in the end winding support structure. In a few cases the advanced state of wear even loosened the screws used for the connection of the outer ring and the support plates or cracked welds between the support bracket and press plate.

Very often the observed dust is associated with a near-resonance operation. This is the case when the natural frequency of the 4-node bending mode of the end winding basket is close to the 100 Hz electromagnetic excitation frequency. However, particularly in large units with inner cooled bars, bump tests have revealed that the natural frequency of the 4-node mode was far-off 100 Hz and was not responsible for the observed wear.

On the other hand, all bump tests have showed a lack of coherence of the response functions when excited with the impulse of a hammer. A lack of coherence means that the individual bars deviate from a perfectly synchronous motion on impact. This is an indication that relative movement is occurring between the bars and the support structure. This supports the conclusion that white dust or the grease-like material is created by friction across a contact surface between neighbouring insulation elements.

Damage is found on baseload generators, as well as on medium load and peak load machines. Wear typically starts slowly – visible as white dust – before it accelerates exponentially at a later stage. There is a tendency for medium and peak load machines that experience a large number of start-stops to develop the symptoms of damage early in their lives. However, the inspection of over 20 design-related units has also found generators that have experienced many start-stops that have had only minor wear. It has also found baseload generators with significant wear.

Frictional movements in the end winding support structure cause the stator bars to loosen, which leads to increased vibrations. As a result the fatigue load acting on copper conductors and brazed connections at the bar ends increases and, eventually, creates fatigue fractures, finally ending in a phase-to-phase or ground fault of the winding. It is evident that in these cases, without pre-emptive measures a stator rewind will be needed after just a short operating time.

3. ANALYSIS OF THE ROOT CAUSE

Figure 1 shows how the support structure of the end winding includes four key elements: a robust steel bracket (1) welded to the press plate holds a thick trapezoidal plate (2) made from fibre-reinforced insulation. Evenly spaced holes, which allow the bottom bars to be tied to the plate, are arranged axially along the inner edge of the trapezoidal plate. The top bars are tied to the bottom bars while an intermediate wedge (3) acts as a spacer element between the end winding cone. The outer support ring (4) is tied to the bottom bars and screwed to the front end of the trapezoidal plates. Along the circumference of the end winding there are typically 15 to 20 of these support elements, depending on the size and type of the generator.

The size and arrangement of the steel bracket and trapezoidal plate create a very solid but rigid support for the end winding. As a consequence thermal expansion and contraction of the stator bars produces significant thermal stresses in the absence of elasticity in the end winding support system.

For example, at the startup of the unit the bars heat up more quickly than the support structure when power is raised. The heat flow from the copper through the insulation into the support structure or the heat flow from the cooling gas into the support structure occurs much more slowly than the temperature rise in the copper, where electrical losses directly generate the heat. Due to the resulting thermal expansion of copper and the 3D nature of the structure, the end winding tries to expand in all three directions: radially, tangentially and axially.

This thermal movement is suppressed by the rigid support. As a consequence high thermal forces develop. The path of this force is from the bars through the ties into the trapezoidal plate, and from there through the steel bracket into the press plate. If the strength of all load carrying members is large enough no parts will experience wear and tear, and the design of the end winding support would be perfectly adequate. However, if there is one weak link in the chain of the force transmitting members, rupture will occur and initiate a wear process.

In the case in question the weakest link is the tied connection between the bottom bar, trapezoidal plate and support ring. The limited elasticity of the short ties is not able to accommodate the full extent of thermal expansion of the end winding. This is particularly true near the bar ends, where the largest thermal elongation of the
winding relative to the press plate is expected. This assumption would agree with the observed damage pattern, which always shows the largest amounts of dust between the support ring and the bottom bars.

Extensive finite element calculations and laboratory tests were carried out to verify the assumed damage mechanism. The finite element model included all key elements of the design as described above. Figure 2 shows the model and, in an enlarged view, a cyclic symmetric section of a typical end winding.

**CLICK TO VIEW FIGURE 2:**
**FINITE ELEMENT MODEL OF END WINDING. RIGHT: FULL-SCALE, LEFT: MAGNIFIED VIEW OF A CYCLIC SYMMETRIC SECTION**

The orthotropic stiffness of the stator bars and the stiffness of the tied connections were measured in laboratory tests and applied to the model using appropriate structural elements. The results of bump tests served to check the validity of the model. Measured and calculated mode shapes, related natural frequencies and dynamic compliances were always found to be in good agreement before a structural analysis was carried out.

At first the thermo-mechanical load acting during a cold startup was simulated. This involved the imposition of temperature loads on all structural members based on measured DCS data from units in operation. The bar temperature was derived from slot and hot gas exit temperatures of bars inner cooled by hydrogen. The temperature of the support structure was determined from the measured cold and warm gas temperatures of the generator. Figure 3 shows the resulting deformation of the end winding.

**CLICK TO VIEW FIGURE 3:**
**DEFORMATION OF A CONVENTIONAL END WINDING DURING START-UP OF THE GENERATOR**

The largest deformation is found near the bar end. The size of the gaps between the bottom bar, trapezoidal plate and support ring indicate the amount of straining and can be viewed as a scale for the magnitude of the force in the affected tied connections. The evaluation of the forces was in agreement with the findings of the white dust; they were highest in the ties between the bottom bar and support ring (large amount of dust) and lowest between the bottom bar and trapezoidal plate near the slot exit (no dust).

The strength of the tied connections was measured in laboratory component tests using original materials, in other words, sections of disassembled stator bars, support rings and plates. The test results confirmed the assumption that the tied connections near the bar end were not capable of carrying the calculated thermal forces. The detailed analysis of the fractures revealed that the cracking mainly occurred between the varnish and protective tape of the main insulation or between the varnish and adhesive layer of the tie (see Figure 4). Rarely was cracking or complete rupture of a tie observed.

**CLICK TO VIEW FIGURE 4:**
**FRACURE OF A TIED CONNECTION DURING A LABORATORY COMPONENT TEST**

### 3.1 THERMAL BLOCKING IDENTIFIED AS ROOT CAUSE

Following the startup analysis of the end winding, the finite element model was used to simulate rated load operation. Under stationary conditions the load is mainly determined by 100 Hz electromagnetic forces acting on the end winding. Higher order electromagnetic forces and inertial forces resulting from the vibration movements of the core and frame were neglected.

As in the previous thermal analysis the forces acting on the tied connections were evaluated and the result showed that they were well below the measured strength of the tied connections. Consequently the electromagnetic forces were not considered to be the root cause of the observed wear. However, in the presence of a cracked interface between the varnish and adhesive layers they cause relative frictional movements between the mating crack faces. This is the process that produces the observed white dust.

Again laboratory component tests were carried out to verify the findings of the finite element simulation. Solid and pre-cracked tied connections were prepared and subjected to 100 Hz cyclic loads for over 20 million cycles. While the solid connections revealed no sign of damage at the end of the tests, the pre-cracked test pieces revealed extensive white dust. From microscopic analyzes it was evident that the white dust resulted from the relative movement of the cracked interfaces in the pre-cracked test pieces.

In summary, the results of the detailed root cause analysis allowed identification of this damage mechanism: the blocked thermal expansion of the end winding causes interfaces in the tied connections to fracture during start-stop operation; and subsequent operating loads lead to relative frictional movements between the cracked faces, loosening the interconnection of the end winding basket with the risk of fatiguing the main insulation or the copper conductors or both.

This mechanism does not rely on the near-resonance conditions of the end winding and is found in many units in which the natural frequencies of the 4-node bending mode are well separated from 100 Hz, or 120 Hz in the USA.

### 4. THE SOLUTION

The traditional solution to the end winding wear problem is the replacement of the end winding support and the application of an entirely new design with added elasticity. Due to limited accessibility, this approach requires a stator rewind and is
associated with an extended downtime for the unit and, therefore, with high costs.

To minimize downtime for a stator end winding rehabilitation, Sensoplan followed a different approach and introduced the TET-Design. The basic idea is to make the trapezoidal support plate more flexible to remove the need for a rewind. The main challenge in the development of this new technology was to find a design that overcomes the problem of the very limited accessibility of the end winding support structure for machining operations and, at the same time, resolution of the problem of thermal blocking without compromising the integrity of the stator.

The solution to this problem was found in a modification of the trapezoidal support plate. This plate takes all of the load from the bottom bars and passes it on to the steel bracket. If it is made more flexible it will automatically reduce the reaction force on the bottom bars when they are subject to thermal expansion in operation.

Furthermore this plate is made from a reinforced insulation material. When machined no metallic particles will be released that could degrade the integrity of the high-voltage capability of the end winding. Although access to the end winding is generally very limited, access to the trapezoidal plates is at least possible. However, it does require specialized tools and procedures.

4.1 TET-DESIGN REDUCES THERMAL FORCES SIGNIFICANTLY

The required degree of flexibility was obtained by introducing an H-shaped cut into the trapezoidal plate and eliminating the screwed connection between the outer support ring and trapezoidal plates [see Figure 5].

CLICK TO VIEW FIGURE 5:
TET-DESIGN ADDS FLEXIBILITY TO THE TRAPEZOIDAL SUPPORT PLATE DURING START-UP

When the bottom bars exert an axial force, the H-cut will allow a defined shear deformation of the plate in which the short legs of the H determine the amount of axial deformation. Also by removing the constraint between the support ring and the trapezoidal plate, free thermal movement of the bar end is enabled. This drastically lowers the large force acting on the tied connections between the bottom bars and the support ring.

The magnified scale in Figure 5 illustrates the deformation behaviour of the end winding support during a startup. The upper left and lower right leg of the H have widened while the lower left and the upper right legs have shortened. Figures 3 & 5 provide a comparison of the deformation of the previous and new TETDesign and make the added flexibility self-evident.

Detailed finite element analyzes were carried out to determine displacements, forces and mechanical stresses of the flexible support system for all relevant load cases, in other words, startup, rated load operation and faulty conditions. For the startup load case the results confirmed a drastic reduction of the thermal forces acting on the ties, avoiding the fracture of the varnish and protective tapes, and thus eliminating wear and dusting.

The fatigue stresses acting during start-up and rated load operation at the tips of the short legs of the H were minimized by introducing smooth radii at the tips of the legs. Laboratory fatigue tests were carried out to determine the fatigue strength of different support plate materials. The comparison with the calculated fatigue stresses revealed a large factor of safety, which ensures that the TETDesign offers a durable and reliable long-term solution. The strength analysis performed during faulty conditions further confirmed that the added flexibility does not interfere with the required shortcircuit strength of the end winding.

As a consequence of the added flexibility, the natural frequency of the 4-node bending mode of the end winding dropped by 5–10 Hz, depending on the particular support structure. This is a beneficial effect for units that are operated near resonance. For these generators the TETDesign offers a two-fold benefit: it eliminates wear and reduces vibration amplitudes during operation.

5. FIELD WORK

The installation of the TETDesign does not require the removal of the stator bars. After disassembly of the outer support ring (Figure 1, item 4) a miniature 3-axis CNC milling machine is attached to two neighbouring steel brackets with quick-release fixtures (Figure 6).

CLICK TO VIEW FIGURE 6:
IN-SITU MACHINING OF THE TRAPEZOIDAL PLATE

The milling machine is connected to a computer outside the generator, allowing precise control of the cutting of the trapezoidal support plate. A special tube encloses the cutter and vacuums most of the chips that are released during the cutting operation. To prevent the remaining few chips from entering the generator the end winding is completely covered and sealed.

Special attention was given to the new support ring because the existing one must be cut off for disassembly and cannot be reused. There are two reasons for this. On the non-driven end the phase connectors prevent the installation of a closed ring without debrazing the connectors. Secondly the outer diameter of the end caps is larger than the inner diameter of the ring because the ring sits on the bar ends inboard from the end caps.

Therefore a new support ring was developed that comprises an inner and outer ring, each made up of several segments that are connected along the circumference during assembly. The inner and outer ring have a conical contact interface. This allows the application of a defined pretension force during installation.
The complete field work, that of removal of the outer support rings, the cutting of the trapezoidal plates, the reinstallation of the new support rings and the hot curing of the end winding, takes no more than four weeks and can be done during a normal overhaul. A stator rewind typically takes 12 weeks, so the installation of the TET-Design saves eight weeks of operating time and incurs only a fraction of the costs of a complete rewind.

6. FIELD EXPERIENCE
The TET-Design has been successfully implemented at the 880 MVA generator of the E.ON Scholven power plant’s Unit F in the north of the Ruhr area in Germany. The plant’s six units and 2200 MW output make it one of the largest hard coal fired plants in Europe. It supplies three million households with electricity and delivers district heating to six cities. Process steam goes to the neighbouring industrial area.

During a scheduled generator revision white dust was detected around the directly H₂-cooled stator end winding. The following in-situ check showed advanced loosening of the bars in this area. Looking for a more economical solution than the traditional and costly one with the obligatory stator rewind, plant operator E.ON contacted Sensoplan, which had the appropriate TET-Design available. After a detailed inspection and diagnosis programme, Sensoplan was able to fix in detail the root cause of the damage. The damage was induced by thermal expansion at the end windings support.

The upgrade feasibility and the operational behaviour of the TET-Design was elaborated and presented in a component test stand. Furthermore the long-term integrity under different operational conditions was calculated and confirmed by additional material endurance test programmes. The TET modification for the Scholven generator is designed for around 5000 further start-stop cycles and timely non-restrictive operation at rated power. With specialized knowledge and high-tech CNC tools the Sensoplan engineers improved the stator end winding support with the TET-Design on-site and on time. The good thermal flexibility and the robust behaviour of the upgraded end winding support system could be verified by acceptance tests. Generator recommissioning and operation proceeded successfully.

On behalf of the E.ON Scholven plant operator, Sensoplan checked the generator again some 2200 operating hours and around 100 start-stops later during a scheduled revision. Inspection of the end winding support system upgraded by the TET-Design confirmed that based on the one year of operating experience, the root cause of the damage had been found and eliminated and that the TET-Design modification is a suitable repair method. The end winding support system will be checked periodically so that the longterm integrity of the TET-Design modification can be ensured. The E.ON Scholven 880 MVA generator is ready now for further numerous efficient and economical operating periods.

7. CONCLUSIONS
The presence of friction dust on stator end windings is an alarm signal that indicates looseness and wear. If left unattended severe damage or even a total spontaneous breakdown will be the inevitable consequences.

For all series of air and H₂ inner and outer-cooled generators with stiff end winding support systems that block the thermal relative movements of the stator bars, Sensoplan offers the patented and operationally proven TET-Design.

Installed in due time the TET-Design modification allows the recovery of the end winding system with these substantial improvements and benefits:

- The root cause of the damage is eliminated
- The end winding support system gains thermal flexibility and improved robustness
- In-situ installation without a stator rewind
- Savings of plant downtime of eight weeks compared with the traditional stator rewind

These features mean the Sensoplan TET-Design provides the best cost-benefit ratio available on the market.
Diagen: A New Approach to Generator Diagnostics

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ABSTRACT
Diagen is a new diagnostic tool for the correct assessment of the condition of a generator and its performance. Diagen is a modular and embedded system that collects, analyzes and stores data from different sensors that are applied to a generator's components, such as a sensor for partial discharges from and vibrations in the stator winding, and a flux probe for the rotor winding or shaft current.

Diagen is applicable to all types of generator, turbo and hydro, of any technology and from any manufacturer.

This diagnostic tool can:
1. Perform continuous and real-time on-line acquisition
2. Perform real-time analysis of data
3. Trend all generator parameters
4. Create alarms when abnormal situations arise

It also allows a remote web connection so that Ansaldo generator diagnostics experts can help power plant maintenance technicians evaluate the behaviour of an electrical machine.

The system is based on a real-time FPGA processor. Signals can be transferred to the control room through the power plant's Ethernet by TCP/IP or by OPC.

Diagen uses predictive diagnostics to reduce fault risks. It is also easily implemented on an operating machine as a retrofit during overhauls.

An additional benefit is the cost saving it provides. There is no need for a generator specialist to be on-site for measurements and evaluation, and there is no interruption of operation. It also reduces the risk of unplanned outages.

1. BACKGROUND
The increasing attention that power producers are paying to improvements in the reliability and lifetimes of their machines in power plants is leading manufacturers to develop and supply tools and packages suitable for controlling the behaviour of components. This control is in essence performed by monitoring the parameters of machines, elaborating rapidly and diagnosing carefully. Ansaldo Energia has a long tradition of manufacturing components for electricity generation and of supplying monitoring and diagnostics systems for such machines.

This paper will discuss a monitoring and diagnostics system called Diagen, supplied by Ansaldo for rotating electrical machinery. Typically turbogenerators are two-pole synchronous machines driven by gas or steam turbines. They operate at speeds of 3000 rpm or 3600 rpm at 50 Hz or 60 Hz. Hydrogenerators typically have high pole numbers. The higher the pole number, the lower the speed of revolution and the higher the diameter of the stator and rotor air-gap. So there are different parameters to control.

The purpose of online monitoring of electrical generators is to continuously be aware of the performance of the unit and to evaluate machine behaviour throughout its operating life by analyzing trends in generator parameters.

In all units, base monitoring is always achieved by means of common instrumentation such as temperature detectors, pressure gauges and vibration pick-ups. Moreover the recommendation is for additional dedicated monitoring devices to be installed in the generator to control other operating parameters and to make monitoring of the machine more complete and accurate.
Providing the generator with a suitable and complete monitoring system will allow the prediction of trouble through early warning, before a fault occurs and before costs are incurred by forced outage. This results in more reliable operation of the machine and makes possible a maintenance schedule that is more fitted to the actual condition of the generator, thus improving the availability of the unit.

A distinction must be made between stand-alone and integrated systems. Generally in the first case, one or more functions are controlled separately. In the second, different parameters are correlated and connected together. In addition there is an important distinction between offline and online techniques. Only with online techniques are systems or sensors permanently installed in the plant. Data are or may be read continuously or whenever desired. Offline techniques are mainly used for conventional planned maintenance while online techniques are the basis for more modern, predictive maintenance.

In the past, the approach was to perform offline tests during generator outages, ranging from a weekend stop to a planned maintenance overhaul. In this case, one or more specialists had to travel to the power plant to perform the tests, collect data, analyze them and supply a final report to the customer. This procedure would then be repeated to define a trend. Online tests were subsequently introduced but specialists still had to travel to the power plant. Then came the introduction of remote acquisition of data by online systems permanently installed at the site, negating the need for the specialists to travel to the site and enabling the real-time assessment of machine status.

2. THE NEW APPROACH: THE DIAGEN MONITORING SYSTEM

Diagen is an integrated diagnostic system designed and developed by Ansaldo that can acquire, collect and manage data from different sensors installed in the electrical generator. It continuously performs on-line monitoring of the machine during its operation.

2.1 TECHNICAL CHARACTERISTICS

Diagen is a modular package (see Figures 1 and 2) based on hardware and software platforms.

The modules available are:

- CORALB, for shaft current and voltage
- CORTROTP, for the air gap flux probe
- SCAPAR, for stator winding partial discharge
- TEMAV, for stator winding overhang vibrations

An industrial PC screen allows generator data to be continuously monitored. The choice of monitoring devices to be installed in the generator, in other words, which modules are applicable in each specific case, usually depends on the power and voltage rating of the unit.

2.2 DIAGEN MODULES

This paper now describes briefly the modules implemented in Diagen. For more detailed information about each monitoring device, reference shall be made to relevant technical descriptions provided elsewhere. These modules represent all the possible monitoring systems that can be acquired and managed by Diagen.

For the monitoring sensors and devices that are provided and applicable in each case, this paper will make reference to Ansaldo’s scope of supply.

2.2.1 CORALB, FOR SHAFT CURRENT AND VOLTAGE DETECTION

Diagen enables the continuous monitoring of generator parameters during machine operation according to the type of devices installed in the machine. It allows real-time measurements, the evaluation of trends and FFT analysis, and makes available all required alarm signaling.

In addition to local direct monitoring on the Diagen board, signals and related alarms can also be transferred to the plant DCS, either by hard-wiring, which is the standard solution, or by OPC Ethernet when required.

Diagen is a powerful device that supports utility maintenance technicians by allowing:

- The easy reading of data as there is one single integrated system
- The easy detection of the degradation of the trend in generator parameters over the lifetime of a machine and predictive diagnostics to reduce fault risks and the high costs of a forced outage
- The optimized scheduling of maintenance tasks and the saving of time in the assessment of the generator condition

Diagen can also transmit acquired signals to Ansaldo’s head office supervisory system. This means Ansaldo generator specialists can provide direct support if such a facility is foreseen in the scope of supply.
Monitoring of the shaft current and voltage is one of the most common practices in the safe and reliable monitoring and protection of the generator. CORALB is the system that Ansaldo has developed over recent decades for the protection of the shaft voltage and current. It prevents the machine from being operated when the shaft voltage and current reach significant values beyond which damage can occur to the bearings of the whole power train and to the generator hydrogen seals in the case of H2-cooled units.

In order to prevent such damage a common practice is to install sliding contacts to ground the shaft at the turbine end and to insulate the bearings, seals and piping at the opposite end of the generator.

The first provision discharges to ground all currents caused by electrostatic charges. This prevents the voltage from reaching a critical level and the voltage that arises along the generator shaft from affecting the other shafts of the power train.

The second provision makes negligible the currents caused by the shaft voltages that are induced by magnetic asymmetries and keeps low the currents originated by capacitive coupling between the field winding and the rotor body.

In order to reduce maintenance and check costs, and to ensure that any indication of deterioration of these provisions is timely, it is important for the monitoring of the shaft voltages and the measurement of the currents flowing along the shaft of the generator to be continuous.

The CORALB system provides on-line monitoring of the shaft grounding conditions, shaft voltage and current measurements, diagnostic messages, and alarm signals.

2.2.2 THE CORTROT-F FLUX PROBE FOR THE ONLINE DETECTION OF A SHORT CIRCUIT IN THE ROTOR WINDING INTER-TURN

The use of permanently installed air-gap probes offers important benefits in the monitoring of turbogenerator rotor windings, mainly for the detection of inter-turn short circuits, without requiring the removal of the rotor. The rotor winding condition can be monitored and trends can be evaluated so that a decision can be made for a specific overhaul.

This type of monitoring has these advantages:

- Detection and localization of inter-turn short circuits in the generator rotor
- Estimation of the type and extent of the short circuits
- Scheduling of shutdowns can be in accordance with the rotor condition and estimation of overhaul extent
- Saving of maintenance costs
- Support for analysis of rotor vibration phenomena

Radial coils assembled on probes installed in the inner diameter of the stator core detect large radial flux density variations as the rotor slots pass by it. These flux measurements are influenced primarily by the ampere-turns in the rotor. As a basic approximation, the change in the flux density is proportional to the ampere-turns of the individual slots. Inter-turn faults will cause a reduction in the peak value of the received signals as the corresponding slot passes by the probe. The rotor flux analysis gives the following outputs: online inter-turn short circuit identification and diagnostic messages, for example coil position.

2.2.3 SCAPAR: MEASUREMENT OF PARTIAL DISCHARGE FROM THE STATOR WINDING INSULATION SYSTEM

The on-line device for monitoring partial discharges is called SCAPAR. It was developed to measure, acquire, process, and distinguish discharges inside stator bars insulation, discharges on stator winding coils overhangs and discharges in the airgap between the stator bars and stator core.

During operation the stator winding insulation system of a generator is subjected to the combined action of voltage, thermal, environmental and mechanical stresses. These age the insulation system and cause a consequential change of partial discharge (PD) characteristics. It has been experimentally established that the best test methodology concerning the evaluation of PD is based on the acquisition of the partial discharge amplitude distribution (PDAD). This shows the PD events as a function of their amplitude and phase. Such measurements performed online provide not only the advantage of avoiding machine shutdown but they also detect any influence by different generator output conditions on PD activity. Measurement is taken by capacitive pick-ups installed outside the machine. For each stator phase, one condenser is assembled on a generator terminal and one condenser on the bus duct. The measurement is then acquired as a difference between the readings from the two sensors. This allows strong attenuation of common-mode noise that arises from plant outside the generator winding.

The analysis of the 3-D distribution shape, and especially the potential to compare the PDADs acquired in the same operating conditions at different times, means significant information can be obtained about the integrity of the insulation system, its status and the type of possible defects.

2.2.4 TEMAV, FOR MONITORING VIBRATION IN STATOR WINDING OVERHANGS

Radial coils assembled on probes installed in the inner diameter of the stator core detect large radial flux density variations as the rotor slots pass by it. These flux measurements are influenced primarily by the ampere-turns in the rotor.
On-line monitoring of stator end-winding vibration is aimed at the timely detection of the loosening of end-winding bracing. It is important to measure vibrations directly at the end-windings. Because these are at high voltage it is necessary, for reasons of safety, to use sensors based on fibre optics to transmit the signals.

The monitoring system consists of a group of fibre-optic accelerometers and an optoelectronic unit for conditioning the signal coming from the sensors.

The signal-conditioning unit provides an analogue output voltage that is directly proportional to the instantaneous acceleration of each sensor in a specific direction.

CLICK TO VIEW FIGURE 7: THE DIAGEN SCREEN SHOWS TEMAY OUTPUT

Correlation of the analysis of the measured vibrations with the generator output current and a readings trend over time allows the prompt detection of any loosening of the bracing and support system for stator end windings.

The installation of accelerometers along the winding on both sides of the generator will also allow identification of the specific locality of trouble.

3. RECOMMENDED APPLICATION OF GENERATOR MONITORING

Based on its experience Ansaldo has listed in Table 1 its recommended implementations of monitoring systems for new units according to the type and rating of machines.

CLICK TO VIEW TABLE 1: AEN’S SUGGESTIONS FOR GENERATOR MONITORING

These recommendations are general guidelines that may vary from case to case depending on specific customer requests and additional evaluations.

In an actual list of monitoring systems, reference shall always be made to Ansaldo’s scope of supply included in the bid. The particular designs and configurations of hydrogenerators mean that only CORALB and, for high-voltage ratings, SCAPAR modules are applicable.

For service purposes different Diagen configurations can be chosen depending on factors such as operation feedback and the results of fact finding.

Diagen’s flexible design means that over a generator’s lifetime, monitoring modules can be added – along with relevant instrumentation on the machine – that were not originally foreseen.

Table 2 summarizes required machine conditions for this type of implementation on existing generators.

CLICK TO VIEW TABLE 2: REQUIREMENTS FOR THE IMPLEMENTATION OF MONITORING SYSTEMS ON EXISTING GENERATORS

The time required for such implementations will vary depending on both the type of the machine and the plant configuration.

4. CONCLUSIONS

Diagen is a new diagnostic tool for hydro and turbogenerators that have been supplied by Ansaldo Energia or other manufacturers.

Diagen is a step forward in a market-driven philosophy that allows the customer to directly assess the generator and receive updates from the Ansaldo head office via a remote connection. Diagen is now available in the market after having been applied to generators in Italy and other countries.
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How End-users and Vendors Should be Facing the Underestimated Problem of Cyber Security in Power Plants

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ABSTRACT
In this paper we will show how security is still an underestimated problem. We present recent work on standardization that is still very much work in progress. This paper describes the confusion in the industry over the plethora of approaches to standards. We point out a pragmatic approach that recommends actions for end-users and vendors. Finally we present a real-world assessment of standards in a European power plant.

1. INTRODUCTION
Cyber security for industrial automation and control systems (IACS) has been much discussed in the recent past. There is a lack of solid data on incidents and attacks available for research. Publicly known vulnerabilities in IACS are still comparatively few. Despite this there is common agreement among experts that IACS need to address cyber security better[1], [2], [3], [4].

Regulations such as NERC CIP reflect this need and standards such as ISA 99/IEC 62443 or IEC 62351 are trying to help the industry achieve better levels of security [5]. However, the standards are still work in progress and a common approach across all standards and regulations is not yet apparent. Furthermore the installed base in use today cannot simply be moved to new systems with new security designs. However, there is a lot that can be done with existing systems and often this is not fully leveraged. In this paper we explain how we see the value and the role of standards and regulations, where we perceive difficulties in pushing for better security, how we see responsibility for security dividing among sections of the industry and how we think existing systems could be improved with regard to security. Finally, we present a case in which we have worked with a customer and in which a good level of security can be achieved with the security solutions that are available in the market today.

2. STANDARDIZATION IS A WORK IN PROGRESS
Today the control system industry is very concerned about open standards – for various good reasons. Only open standards can ensure that investments in installations that have lifetimes measured in decades can actually be supported over those lifetimes without significant lock-ins or high risks. For example, open communications protocols support the interoperability of systems from different vendors and reduce lock-in. This is because other vendors can deliver substitute products. Open safety standards reduce transaction costs because they decrease information asymmetry about product features that the customer finds difficult or even impossible to observe.

Various efforts in standardization and regulation are ongoing and are pursuing different goals. Regulations typically attempt to ensure the continuous, reliable and secure operations of critical infrastructures on which the regulating nation depends. Regulatory authorities have the power to enforce their rules either through incentives for compliance or through penalties for non-compliance. In practice it is the latter that is more often seen.

Examples of regulation in the cyber security space include the NERC CIP rules, which are effective in the power industry in North America, or CFATS, for facilities that handle classified chemicals in the USA.

Then there is a group of standards that attempt to raise quality in the industry by defining a minimum set of requirements commonly agreed on by a committee. However, the bodies issuing these standards themselves do not have the power to enforce them either through incentives for compliance or through penalties for non-compliance. In practice it is the latter that is more often seen.

In this paper we will show how security is still an underestimated problem. We present recent work on standardization that is still very much work in progress. This paper describes the confusion in the industry over the plethora of approaches to standards. We point out a pragmatic approach that recommends actions for end-users and vendors. Finally we present a real-world assessment of standards in a European power plant.
Examples of this include the ISA 99 standard for control system security, the ‘Requirements for Secure Control and Telecommunication Systems’ white paper from the German Association of Energy and Water Industry (BDEW) and the DHS Cyber Security Procurement Language for Control Systems.

Another group of standards attempts to achieve a different goal: to target the interoperability of security functions. These standards usually specify a communications protocol or security functions for a communications protocol. Bodies issuing such standards are usually international industry associations or dedicated standardization organizations, such as the ISO and the IEC. Of course, the authors are aware that these bodies also issue standards that belong to the second category. Other examples of such organizations are user groups for specific technologies, such as the DNP User Group. These standards are not mandatory unless they are referred to by regulatory authorities. Examples in this category include the IEC 62351 series or the security specifications for DNP.

Finally, there are corporate standards that are usually defined by large corporations that see a lack of other guidelines or standards, either because none exist or because existing ones need to be tuned to the corporation’s specific environment.

The objective of these standards is usually multifold. They are to be reused and thus lead to a harmonized approach to and implementation of security across the entire enterprise. They reduce the level of skills and competence necessary at every site as central experts provide guidance. They also reduce the effort that goes into specifying new systems during their acquisition.

There is obvious potential for interdependencies and reuse among these categories. For example, regulations and corporate standards can refer to and enforce compliance with national or international standards. National or international standards and corporate standards can refer to and mandate, or at least recommend, the use of secure and interoperable technology.

Vendors and end-user both benefit from these kinds of interdependencies and cross-references as they can reuse solutions developed elsewhere and thus can foster consistency in the approach to and implementation of security. However, these interdependencies and cross-references can also make life harder as they can lead to a jungle of standards and guidelines which makes it difficult to maintain an overview and to avoid gaps and contradictions.

Specific care has to be taken when standards are applied in a context different to the one they were designed for. For example, the ISO 27000 series of standards primarily addresses enterprise information systems. Applying the requirements defined in them to a control system can lead to undesired or even dangerous consequences, such as an operator losing view because of screen savers or being locked out of a workstation because a password has expired.

The ESCoRTS project funded by the European Union Seventh Framework Programme (FP7) has compiled a list of 37 standards and guidelines [6] that describes which objectives each of these standards addresses, what their scope is and what their status is. The project also provides a brief overview of the content of each standard.

The length of this list, despite probably still not being 100 per cent complete, shows that there is a multitude of standards and guidelines.

Regarding this multitude, there is no fixed specification for vendors to build products against, for system integrators to build systems against or for end-users to base their procurement and operations on. Fixing this requires time and joint effort by the entire industry. This challenge has been accepted by the industry and there are good examples of working communities with broad representations and some working groups that had been drafting competing standards that have merged their efforts. The ISA and the IEC are working together and the output of ISA 99 will be submitted for comments and votes to the IEC in parallel with the ISA. As a consequence it is to be expected that IEC 62443 and ISA 99 will end up being identical and will form the leading, generic control system security standard.

3. CONFUSION, RELUCTANCE AND TRUST

The diversity of regulations, standards and guidelines in different categories and from different authors – sometimes contradicting each other – have led to confusion in the industry about which is the right path forward. This has led to a reluctance to invest in any one technology or approach – and even a reluctance to use existing options for security as they are available in today’s installed base – as there seems to be little experience and end-users are risk averse and rightly so.

Trust between different players is not yet widely established because which of their different interests potentially conflict is not fully clear and parties question the relevant competencies of other parties. Examples of such conflicting parties include:

- Enterprise IT and control system IT – Enterprise IT is often formally assigned the responsibility for cyber security for the entire corporation and has dedicated security teams with a relatively stable and established approach to cyber security. However, it usually has different priorities and deals with systems with a different criticality than control system IT does [1]. Control system IT is usually formally responsible for safe and continuous operation of the production process, often has little to no cyber security expertise and is used to operating fairly isolated systems.
- Vendors, system integrators, service providers and end-user – end-users, sometimes forced by their enterprise IT, require certain solutions from system integrators and vendors that may adversely affect the availability of control systems.
Service providers, integrators and vendors sometimes try to force the end-user into using their solutions for remote support, sometimes enforced with a statement of no support. When end-users are assisted by service providers or enterprise IT without the right control system background, this can lead to conflicts in proposals and implementation strategies and solutions.

However, there are examples in which these conflicts have been addressed and overcome successfully. In several countries representatives of different players (vendors, system integrators and end-users) have formed communities to exchange information and to collaborate on specific problems. Examples include:

- The information exchange boards initiated by the UK’s Centre for Protection of National Infrastructure
- The public-private partnership in the cybercrime information exchange initiated by the Dutch NICC and the Swiss Reporting and Analysis Centre for Information Assurance
- The European SCADA and Control Systems Information Exchange, which coordinates and extends its own and other national activities across Europe
- The global MERIDIAN network for sharing information and good practices on critical information infrastructure protection

All of these initiatives have brought together various players in the industry to exchange information and to share experiences. This type of collaboration helps to establish trust within the community and, based on this trust, critical issues can be addressed in an open and productive manner.

4. CONTINUOUS PROCESS – ADDRESSING THE RESOURCES PROBLEM

Security cannot be achieved by taking an install-and-forget approach. It is not a case of buying and deploying once. Security requires policies and procedures, and organizations with the proper resources and culture. Both end-users and vendors or system integrators often see what is needed but struggle with the allocation of the needed resources and with culture change. They are in competition with other business activities that often have a more obvious and quantifiable return.

Processes are not only interorganizational but many processes actually have to span from the end-user to the vendor — potentially with a system integrator in between. An example is patch management and vulnerability management. Again the international standards and collaborative activities in various committees as previously listed are good examples of where the interfaces for such processes between vendors and end-users could be defined.

It starts with vendors developing products using a secure development method to develop robust products with the necessary security features. Also system integrators need to use these features and sometimes complement the control system products with additional controls and, in general, build security into the system design as well. Furthermore end-users must insist on security requirements in their procurement otherwise vendors and system integrators who are spending efforts on these aspects will not be able to benefit from the extra effort and therefore will not be competitive.

Finally the end-users must adapt their operations and internal organization to maintain the security of the installed systems and to operate them in a secure manner. Most regulations actually recognize this fact and are eventually applicable to the end-user, for example NERC CIP and CFATS.

Similarly the standards that attempt to raise quality in the industry by defining a minimum set of requirements commonly agreed on by a committee all have significant sections on operational requirements that need to be met by the end-user organization.

Of course, the system integrators and vendors have their share of responsibility in providing systems and products that have the necessary features to support these operational principles in an efficient manner, along with the necessary documentation and guidance on how to use them.

5. WHAT IS ECONOMICALLY FEASIBLE?

It should now be obvious that the control system industry needs to make a substantial effort to address the issue of cyber security for critical infrastructures. Just like any effort, this one will not be free. There will be significant costs. One question to be answered is where the efforts are spent most efficiently, in other words, with the best cost-benefit ratio.

The common goal must be to minimize risks related to cyber security. Thus it is again obvious that a risk management approach should be followed. Usually this involves the identification, assessment and prioritization of risks by careful analysis of assets, their criticality and their vulnerability to attacks, as well as likelihood of attack. This is then followed by coordinated efforts to minimize, monitor and control the probability and/or impact of security incidents [8]. Typically investments are prioritized using an expected return on investment (ROI). Models for the calculation of a return on security investment (ROS) have been proposed [9], [10] that all relate the cost of security controls to the reduction of risk they achieve when implemented.

Implementing these models, however, is not as simple a task as it may sound. While there are several security controls available along with decent experience from their usage in the enterprise IT world, not all of them are equally suited to control systems as they may conflict with the requirements for continuous and safe operations as are typically found in control systems.

An example is the way commercial intrusion-prevention systems...
have false-positive rates that are usually unacceptable in control systems. Thus the quantification of the reduced risks due to deployment of these controls is difficult. There are not sufficient data available from experience. Furthermore, the costs of deploying security controls can be significantly higher in control systems than they are in enterprise systems because changes to the system have to follow strict change-management rules, including significant testing. Those security controls that cause frequent changes to the system under consideration fall into this category, such as patch management. It follows that the quantification of the deployment cost of these controls is not simple either. Again, sufficient data from experience are lacking.

Last but not least there is little reliable data on typical attacks, or more generally threats, that a control system is exposed to. Several vulnerabilities are known in control systems, both specific ones in implementations such as protocol stacks that lack sufficient robustness but also fundamental ones in conceptual design, such as protocols that do not provide security mechanisms.

However, this information about vulnerability is not sufficient as it gives no information about how likely their exploitation is, in other words, how likely an incident is to occur and what the associated consequences are. We also see that the quantification of risk related to cyber security is difficult and thus the risk reduction gained by specific security controls is also difficult to quantify. Hence the proposed calculations concerning ROSI are currently not practical.

For system designers to select appropriate security controls, in the long term this must be replaced by a solid understanding of the threat landscape, including cost structures and empirical data on threats and vulnerabilities, as well as their exploitation or attempts to exploit them.

Gathering these data could be a worthwhile activity for joint interest groups that comprise different players, such as the groups previously mentioned. However, even without such reliable data from the field, the most promising path forward towards more secure control systems is the wide adoption of secure development methods, in other words, by embedding security into the system development lifecycle. This includes threat modelling, for which feasible approaches have been presented [11, 12], security requirements for engineering and secure system design, as well as secure coding practices and security testing.

As long as substantial experiences and established practices specific to control systems do not yet exist, there is a lot that can be learned and reused from other software industries.

Microsoft’s Secure Development Lifecycle model (MS SDL, [13]), the System Security Engineering Capability Model (SSE-CMM, [14]) or the Building Security In Maturity Model (BSIMM, [15]) can serve as starting points. In all stages, there needs to be a careful consideration of the impact that security controls may have on the continuous operation of a control system or a component of it. In cases where this impact is deemed to be too high, compensating controls around the system or its component should be designed that provide the protection of a subsystem that in itself cannot be secured further.

Another issue that causes significant overhead and cost is the multitude of and inconsistency among security requirements defined in the different regulations and standards. In the control systems industry in particular many end-users operate critical infrastructures. If there are disruptions, potentially caused by cyber security incidents, the operators may be held accountable for the enormous social costs these disruptions can cause. For example, an accident in a nuclear power plant leading to the leak of radioactive material or the spilling of oil into the ocean due to the disruption of an oil rig’s operation.

To avoid these incidents as much as possible and to avoid liability for those that still cannot be prevented, end-users must show that they have done everything they reasonably can be expected to do. This is their due diligence. The definition of the scope of due diligence is often difficult to establish in court cases. However, if there is a commonly accepted industry standard or a set of regulatory requirements, these often serve as the baseline for due diligence. Thus compliance with a commonly accepted standard can also reduce liability risks.

Furthermore, for an end-user in a procurement phase, the multitude of existing standards and regulations causes significant overhead in selecting the right set of requirements from different sources. Here the advantages of a single, comprehensive standard become obvious – for vendors and system integrators too.

The less diversity there is in the requirements of different end-users, the less complex it is for a vendor or system integrator to design products and reference architectures for systems that can comply with those requirements.

Efforts such as the DHS Cyber Security Procurement language for Control Systems or the generalization of Shell’s security requirements in the WIB/NICC in the Netherlands are steps in the right direction towards harmonizing requirements for new systems and should eventually converge with a generic standard as a baseline and some industry-specific additions and adaptations to cover the specific needs that an industry such as power generation or oil and gas may have.

However, compliance with robust security standards and guidelines, once they are available, will primarily be feasible for new products and systems despite the fact that standards such as ISA 99 particularly address the need to integrate what is often referred to as legacy systems or legacy equipment. ISA 99 foresees the use of compensating security controls that are applied to zones that may then contain and protect assets that themselves can only provide lower protection than would normally be required for them.

Given the common lifetime of control systems, which is measured...
in decades rather than years, the installed base that is in use today also needs to be addressed. A rip-and-replace approach is economically not feasible as the investment needs to provide return before there can be a substantial upgrade or replacement. Therefore the need exists for economically feasible retrofit solutions that can provide a sufficient level of security for existing installations. In order to find these solutions, strong collaboration between vendors, system integrators and end-users is necessary that is based on mutual trust.

6. WHAT CAN OR SHOULD END-USERS DO?
When looking at the total scope of security most of it comes directly under the responsibility of the end-user. The most obvious topics here are to establish a security programme in which responsibilities and policies are clearly defined. There is a lot of information available in standards and literature that guides end-users on how to implement this. It is based on years of experience in the information security domain. In this case we would like to provide some insight into a more pragmatic approach that could be used to improve the security resilience of a system with measures that are a much closer fit with the nature of control system administrators and their organizations.

There are a number of things that can be done at relatively low cost and with relatively low impact. They can be implemented in most of the active and classic products, so they do not require costly replacements or upgrades.

However, we need to be realistic. Updates to newer revisions, for example the application of security patches, is often required rather than upgrading to newer releases or even switching to new products. These types of updates are feasible in most cases with acceptable effort or acceptable impact on the system. Keeping the system up-to-date is one of the most important things to do as this enables all sorts of additional activities without impact on availability and performance, such as the supported use of antivirus software and the installation of validated security patches.

Another topic to be addressed by end-users is keeping track of installations. Configuration drawings and installation documents need to be kept up-to-date. Forgotten servers or network connections are probably the biggest vulnerabilities in existing installations. Consider the fact that what you do not know you will not administrate or keep track of. These nodes and connections are the most viable entry points for adversaries.

Making backups is an everyday task that control system administrators perform. What could be improved is what use backups are put to. In most cases they are not verified or tested as to whether they will be usable after a disaster.

Also, in a lot of cases, more information is needed besides the backups to be able to rebuild a system in a short time or to rebuild it at all. Disaster recovery is a process that is comprehensive and needs regular verification but its benefits are huge. Having the process operational again quickly is critical, and extended outages are usually extremely costly in the control systems domain.

To support a defence-in-depth strategy, the nodes in a system need to be hardened, and this can be done with limited effort. Information is available about how to do this for most systems, but in some cases specific deployments and combinations of software mean more investigation is required.

Finally logging and role-based access control are functions that have existed in DCS and SCADA systems for a long time. However, they are often not used to their full extent. The use of individual accounts and associated account management would improve the security of the system and, more importantly, the audit capability of the system. Unfortunately it is still the case that many people share only a few accounts, and passwords are known and used by even more people. They are usually the same for multiple installations as they never get changed.

It is common for logging to be enabled. In some cases the logging contains useable security-related events. Unfortunately this information is seldom used. Neither does the culture exist for looking at logs regularly, nor is there time. This is equally true for the most commonly used security mitigation method, the installed-once firewall that separates the control system from ‘all’ malicious activities in the outside world.

These activities require periodic attention. It is good that control system administrators cooperate with other internal and external organizations, such as enterprise IT, and vendor and system integrators, to reduce their burden and make use of existing knowledge and resources.

So in summary we can say that by improving situations by pragmatically using existing features, risks can be lowered considerably.

7. WHAT CAN OR SHOULD VENDORS DO?
Out of the total scope of security there is a small yet important part of it that falls directly under the responsibility of the vendors. It primarily includes the implementation of required security features and the establishment and following of internal processes to allow a secure development lifecycle.

What is required of security features is extremely diverse, and no commonly agreed baseline exists. However, at a minimum the following features should be available in products and systems:

• Account management, including the ability to create individual user accounts and change passwords
• Support for strong and role-based access control
• Hardening, including the use of only those services that are required and operation in a least-privilege environment
• Auditing that allows changes to the system to be tracked
• Recommendations and the necessary support for using antivirus software

• Patch management

These features and abilities are supported by most of the products and systems that are in the active and classic phases of their lifecycles. However, in most cases today the implementation and, more importantly, the maintenance and administration of these features are cumbersome. So a task for the future is to improve the administrator’s situation through better user interfaces and better interaction models. The goal must be a model for security administration and operation that better fits the model of control system administration and operation.

The second most important, and to some extent less obvious and visible, set of activities is in the area of the software development lifecycle. Vendors should establish policies and processes for the threat modelling of architectures and designs, source code validation, product testing and system testing. These topics should be an embedded part of the product and system software development and quality processes.

Post-release, vendors must provide at least these services to support end-users throughout the entire lifetime of the system: patch validation, antivirus validation, and vulnerability management and mitigation.

It is of utmost importance that it is clear to end-users what processes are in place and what information is provided to perform important administrative tasks in a reliable and secure way. When the vendor also acts as an integrator, security must be addressed during the execution of a project, as well as in the services it provides. Topics that are to be addressed in this context are: the FAT/SAT security baseline; verification that security features and functions are implemented and up-to-date; and organizational security training.

This belongs with additional services that can be provided by the vendor/integrator service organizations, and falls under the co-shared responsibility of vendors and end-users. These services should address the customers’ resource problems as described earlier. Examples include: consultancy with regard to secure operations and secure client and server management, which not only includes maintenance of antivirus solutions and patch levels but also the assessment of compliance with the defined security baseline.

Last but not least, vendors also need to cooperate with security technology partners. It is of increasing importance that new technologies like firewalls, NIDS/NIPS and SIEM are integrated in and verified in combination with products and systems. Integration and verification of these technologies will increase the ability to observe total system security and the ability to report on compliance. Besides these technologies, there are security technologies in the periphery of the system that improve system robustness and posture, such as device control, HIDS, antivirus and application white listing.

Another, perhaps less visible, part of the vendor's responsibility is to drive the establishment of industry standards and the application of guidance. In addition to this, vendors should also drive awareness in their own organizations, collaborate with governmental organizations and participate in security-related events. In this way they can also influence the awareness of their end-users.

8. A CASE FOR COLLABORATION

ABB realizes the importance of collaboration between vendors, system integrators and end-users as outlined in earlier sections of this paper. On the one hand, ABB is committed to living up to its responsibilities as a vendor and system integrator in the control system domain. Furthermore we are open to communication and collaboration with our customers on security activities. In this section we present a successful example of such collaboration between ABB and a European power generation customer.

The goal of this collaboration was multifold. On the one hand the customer was interested in a security assessment of a particular power plant, which was entirely redesigned in 2003. The customer was also keen on getting insights into upcoming standards as the assumption is that such standards would eventually be imposed on the customer, either by industry self-regulation or by regulatory authorities.

On the other hand ABB was interested in collecting cases of use in the real-world that show how existing ABB products can be used in a standards compliant operation, how well the actual practice is leveraging existing features and where additional features would provide most benefit.

For both ABB and the customer there was an interest in identifying potential needs for modifications to design guidelines and templates for use in future projects. The hope was that a case of real-world use that applies a draft standard would provide valuable insight into the usability and usefulness of the standard. This would be a benefit to the entire industry and especially the standards committee.

ABB and the customer jointly selected the ISA 99 standard in its current draft status as a basis for this assessment. This is because the common assessment is that – given the joint efforts between ISA and IEC to parallelize the editorial procedures for co-publishing as ANSI/ISA 99 and IEC 62443 – the ISA 99 standard is the most promising candidate for a global, cross-industry control system security standard that has a broad approach and covers the secure operations of a control system and requirements for system design and product functionality.

Given that the ISA 99 standard is still under development, the scope of the assessment was limited to those parts that had been published or at least had been sent out once as a committee draft for comments. This included parts ISA 99.00.01-2007 (the overall framework), ISA TR99.00.01 (security technologies for control systems) and ISA 99.02.01 (establishing a security programme),...
ISA 99.03.02 (zones and conduits and security assurance levels) and ISA 99.03.03 (system requirements).

ABB and the customer then scheduled an assessment of a power plant selected by the customer. The assessment was conducted in an on-site joint workshop over three consecutive days. Before the workshop, the customer was provided with documents such as the latest drafts of the different parts of the ISA 99 standard and questionnaires based on requirements from the standard. Based on this, the customer could define relevant participants to the workshop and collect most of the relevant information, for example corporate policies and procedures, plant operation procedures, system configuration and inventory. All in all, the assessment team consisted of 11 individuals, each with a different background and responsibility. This resulted in a valuable diversity of perspectives and concerns with regard to the security controls available at and applicable to the plant under consideration. The assessment team had representatives from the following organizational units:

- The customer’s research organization, responsible for general guidelines and reference system designs
- The customer’s compliance organization, responsible for corporate policies and procedures for risk management and business operations
- The customer’s enterprise IT organization, responsible for the enterprise IT infrastructure, including, for example, authentication domains and physical and logical networks
- The customer’s plant operation organization, responsible for the continuous operation of the selected power plant
- The ABB system unit, responsible for the system design and the control system used at the selected power plant
- The ABB product unit, responsible for the product design of the system features or additional, compatible security controls could only be introduced to improve the plant’s security or where potential for improvement of the existing product could be identified.

While confidentiality prevents us from explaining the detailed findings concerning the specific plant or specific product features, the following findings or types of findings were achieved in the assessment:

- The ISA 99 standard used as a reference framework is in general highly applicable to the operation of power plants and the control systems involved in them. However, there were some gaps identified in the standard and in general it was noted that the standard is very comprehensive. Thus it takes some time to get acquainted with it. Once it is completed and published and more experience is available, this will, of course, become less of an issue.
- An open analysis of system design, deployed configurations and policies and procedures for operations increased the awareness of existing security controls, both technical and organizational, among the different organizational units of the customer, and between ABB and the customer. The complementary nature of physical and cyber security and operational and technical security controls could only be discovered by a cross-disciplinary team because it was present at the assessment.
- ABB and the customer learned about:
  - The potential for improvement in the product or system design
  - The potential for improvement in the existing deployment of the system, as well as blueprints for future system design using existing product features and compatible, external security controls
  - The potential for improvement and gaps in policies and procedures which were not fully addressing the specific needs of control systems with regard to continuous operations
  - Gaps in the risk management methodology that was not fully addressing cyber security risks

A concluding statement concerning compliance with a standard was not made and not sought, partially because the standard is still in draft form and work is ongoing on several of the documents used in the assessment, partially because some assessment decisions depended on whether an auditor would consider a given security control to meet a requirement or not. This will be shown if auditing guidelines and auditing experience in practice are available for the standard.
9. CONCLUSIONS

Even though the current standardization landscape is a work in progress and can be confusing at times, a pragmatic approach can help to improve the security situation in our critical infrastructure. A lot can be achieved if the industry continuously works together, if organizations trust each other and information is shared, and all players are aware of their own responsibilities and the responsibilities of the industry as a whole.

When we succeed in providing a means of determining a good model for ROI and convincing upper management about this, we will be able to get the required budget and resources. Then end-users will be able to take that additional step besides managing the low-hanging fruit.

Vendors and integrators will have to do their parts, motivated by end-user requirements expressed in the procurement of new products and systems. We are convinced that a collaborative effort between all of the parties described in this paper will result in an increase in security in our critical infrastructure.
REFERENCES

POWER-GEN EUROPE

TRACK 6

OPERATIONS & MAINTENANCE AND PROCESS OPTIMIZATION
Ultrasonic Inspection of Curved-entry Turbine Blade Roots

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ABSTRACT
The drive for increased efficiency in low-pressure steam turbines has seen a proliferation in the number of designs that incorporate larger last-stage blades with curved-entry roots to accommodate the high twist. Such designs create significant problems for ultrasonic inspection because of the reduced land available for probe positioning and the close proximity of the blades to one another.

Cracking of the blade roots and rotor disk steeples occur mainly in the top serration but may also occur in the lower serrations depending on design and operational conditions. RWE Inspection Management has been investigating this problem for several years on designs present at its UK plant and has developed a phased array ultrasonic inspection that provides the most complete coverage possible.

Using highly accurate simulations of individual blade types, a bespoke set of probes and scanning patterns for each blade/disk design can be established and actuated via a tailored manual scanning frame. Application of this inspection in-situ can minimize unit downtime and maintain the highest confidence in component integrity.

In this paper we will explain the design process used and highlight the improvements in inspection quality brought about by this approach.

1. INTRODUCTION
Modern steam turbines have adopted designs with large, final-stage blades with high twist to increase efficiency. While the benefits of these new designs are significant, it has made the inspection of critical blade ‘fir-tree’ root areas much more difficult.

There has been evidence of cracking on a number of blade designs and OEMs request that plant owners have the blades ultrasonically tested every 50,000 hours.

The problem with inspection stems not only from the varying curved geometry of the root but, more significantly, from the lack of accessible lands to inspect the geometry with ultrasound. Other non-destructive evaluation methods are impractical for inspection without removing the blades from the rotor disk, which is a costly and time-consuming practice.

By using phased array ultrasonic testing (PAUT), greater control of the soundwaves used to interrogate the root can be achieved. Combining this technology with powerful simulation software allows for maximum interrogation of the critical areas from the limited lands available. Using the enhanced visualization available with PAUT and by overlaying geometric drawings of the blade root profile increases reliability of inspection considerably.

Bespoke inspections have to be created for each blade design to account for the differences in scale, curvature, blade spacing, root design and critical areas.

This paper will discuss the process of designing a PAUT inspection for curved-entry blade roots, how many of the limitations to testing have been overcome and what can now be achieved.

2. FAILURES
RWE Power International’s experience of failures of curved-entry blade roots began in 2003 at a power station in South Africa. Since then, an increasing number of faults have been found on different blade types across the world.

Failure is usually the result of fatigue cracking in the upper serrations. These are the most highly stressed areas, according to finite element analysis (FEA), as shown in Figure 1, and also represent the area where cracking is most likely to lead to the blade fully detaching from the rotor.

CLICK TO VIEW FIGURE 1:
FEA MODEL OF YON MISES EQUIVALENT TENSION IN CURVED BLADE ROOT SERRATIONS

For the blade design shown in Figure 1, FEA suggests that the greatest stress concentration is in the top serration down from the blade platform, although some FEA models suggest that the second serration has the greatest stress. Operational experience has shown that the top serration tends to be the
most likely to crack, as illustrated in Figures 2 and 3, which show defects propagating in different orientations in different designs.

**CLICK TO VIEW FIGURE 2:**
**CRACK PROPAGATING PARALLEL TO THE BLADE PLATFORM ON A THREE-SERRATION BLADE DESIGN**

**CLICK TO VIEW FIGURE 3:**
**A CRACK PROPAGATING PERPENDICULAR TO THE BLADE PLATFORM ON A THREE-SERRATION BLADE DESIGN**

The defect shown in Figure 3 illustrates another complication of the blade root inspection. The orientation of the defect will not always be preferential for inspection. Again, PAUT is best placed to accommodate the uncertainty in defect orientation because of its use of sectorial scanning through multiple beam angles.

The ideal inspection required for these blades is as follows:

- Detection of cracking originating in the top two serrations in the “fir-tree” root and preferably any lower serrations too
- Detection of cracking propagating in any direction
- In-situ inspection of the blades in the rotor
- Methodology should be applicable to any blade design, although precise NDE equipment will not be

**3. ACCESSIBLE LANDS**

The lands available for ultrasonic testing will vary from one blade design to another; some will have flat wide platforms that are ideal for scanning, some will have almost nothing appropriate. There are two accessible lands that are common to all blade types: the end face of the root and the blade aerofoil. These positions are therefore the most appropriate to inspect from.

Because of the orientation of the serrations and the defects originating from them, most of the scanning will come from the aerofoil surface (see Figure 4), with additional scanning from the root ends to increase overall inspection coverage. If scanning from the platform is possible and can be implemented effectively, then that should also be used, as appropriate.

**CLICK TO VIEW FIGURE 4:**
**AREAS THAT CAN BE INSPECTED FROM THE AEROFOIL ON A 4-SERRATION BLADE DESIGN**

**PHASED ARRAY ULTRASONIC TESTING (PAUT)**

Phased array ultrasound has the same physical limitations as conventional ultrasonic testing. However, there is a far greater level of control and visualization available that helps to overcome many of the difficulties associated with the inspection of curved-entry blade root geometries.

First and foremost is the ability to steer the ultrasonic beam through multiple angles and create sectorial images. These images can then be overlaid with images of the component geometry, as illustrated in Figure 5. Additionally, the probe can be focused at distances shorter than its natural focal length by varying the time delay on the individual elements. This allows the inspector to achieve narrower beam profiles and higher sound intensity in the required areas, thus improving detectability and resolution.

**CLICK TO VIEW FIGURE 5:**
**SECTORIAL SCAN IMAGE OF ROOT SERRATION GEOMETRY WITH DEFECT**

**5. DESIGNING THE INSPECTION**

Once the extent of the accessible lands and critical areas has been identified, then the first stage in the modelling or simulation process is to identify some appropriate transducer characteristics. The most suitable transducers will depend on the acoustic capability of the transducer and on practical considerations, such as size, to ensure that the probe can operate effectively on the curved geometry and also physically fit between blades. Acoustic path lengths are generally small for the inspection of curved-entry blade roots, and typical 12Cr steel blades do not exhibit much attenuation. Consequently, high frequencies can be used, permitting greater axial resolution. Transducer footprint size selection is a compromise between being large enough to keep the critical areas within the probe’s near field and still making good contact with the curved aerofoil. The process is not entirely straightforward because of the refracted angles required to get the sound into the desired locations. This requires both a Rexolite wedge and electronic steering to achieve the full range of angles.

The addition of the wedge increases both the height and the footprint of the probe. Both factors will reduce the effective aperture of the probe, particularly at high angles. Reducing the effective aperture will reduce the near field of the probe, restricting focal capabilities and reducing the sound intensity. Careful consideration of all these factors, combined with some straightforward calculations, should produce some plausible probe parameters that can be used in the next stage of simulation.

Figure 6 shows a diagram of a four-serration blade and the angles and path lengths required to hit all serrations from the probe position on the convex side of the aerofoil. Note that to cover the serrations on the other side of the blade root would require scanning from the convex side of the aerofoil, which would increase the maximum angle and path length even further.

**CLICK TO VIEW FIGURE 6:**
**ANGLES AND PATH LENGTHS TO INTERROGATE SERRATIONS FROM OPPOSITE AEROFOIL**
Using the desired probe parameters the beam profile for various angles within the sectorial scan can be simulated and the probe moved to find the optimum scanning position. Ideally this should give good sound intensity and a narrow beam profile for all the critical areas, as shown in Figure 7.

**CLICK TO VIEW FIGURE 7:**
**BEAM PROFILE FOR ANGLES AND PATH LENGTHS APPROPRIATE TO CRITICAL AREAS OF A FOUR-SERRATION BLADE ROOT**

Producing beam simulations like the one shown above can help to limit the number of appropriate transducer designs and thus reduce the work involved in the next stage, which is proving the detection capability of the inspection. This is a two-stage process, starting with defect interaction simulations, followed by proof on replica blades with artificial defects. The position and size of the artificial defects will depend on information gained from the simulation process. The simulation process begins with simple ray tracing to ensure that sound can be returned from defects at the critical locations. The defects for the simulation are planar slots, which can be recreated in validation tests using electro-discharge machining (EDM) notches. Variations in slot size, position and orientation can be made to gain a rough understanding of what can, theoretically, be detected in each critical area.

This is the first step in defining the minimum detectable defect size for given critical areas. Once it has been established that the sound can get to and from the relevant areas of the root, then the full defect interaction simulations can be run, which will show defect responses and geometric responses across a full sectorial scan image. An example plot is shown in Figure 8 for a four-serration blade root, with the ray trace for a shallow-angle beam impacting on the fourth serration overlaid.

**CLICK TO VIEW FIGURE 8:**
**RAY TRACING AND DEFECT RESPONSE SIMULATION FOR A FOUR-SERRATION BLADE ROOT GEOMETRY**

This process can then be repeated for all relevant transducers from all accessible lands to determine the theoretical minimum detectable defect size. This value may well vary for different serrations, for different parts of the blade geometry and for non-preferentially oriented defects.

Although the simulations produce excellent and accurate results, the technique must be proved using real transducers on a replica blade. Slots are inserted into the replica blade root at specific locations and their size and orientation will be related to the results of the defect simulation. A direct comparison of the simulated and real-life cases can then be drawn.

If there is good agreement between the two, then confidence in the technique increases and the detection limits can be quantified in terms of equivalent detectable slot sizes. If there is not good agreement, alternative probe parameters may be required or more conservative defect size estimates may be appropriate. Figure 9 shows a comparison between the simulation and the validation reference piece.

**CLICK TO VIEW FIGURE 9:**
**DETECT-RESPONSE SIMULATION FOR A FOUR-SERRATION BLADE ROOT GEOMETRY COMPARED WITH A REAL-LIFE SCAN OF BLADE GEOMETRY WITH EDM SLOTS**

Where it is desired, this validation can be extended to include non-preferentially oriented defects, inclined more towards the transducer or further away. When such artificial defects are created using EDM slots, they are actually more difficult to detect due to the lack of facets on the major plane of the defect. In situations where these EDM slots can be detected by the technique, it gives excellent confidence in being able to detect a real (faceted) defect.

Detection rates can be increased significantly in critical areas prone to cracking, such as the concave serrations near the leading edge of the blade, if the probe can be skewed. Where manual scanning of the blades is possible, skewing is straightforward but time-consuming.

The ability to use manual scanning depends almost entirely on the blades being removed from the rotor disk. This makes the whole process very long and expensive, which is why RWE Power International has developed an in-situ capability. This uses a manual scanning frame unique to each blade design that allows the probe to be skewed at any position across the concave and convex faces of the aerofoil.

While skewing the probe maximizes the detection capability of the inspection, it does not readily lend itself to encoded scanning. This can be overcome by using 2-D matrix arrays to electronically skew the beam while encoding the data along a single scanning path. This method is expensive and creates data files that are unnecessarily large. It also requires larger probes, which may limit the ability to inspect designs in which the blades are very close together. We are exploring novel ways of overcoming this problem but are not yet in a position to divulge this information.

6. CONCLUSIONS

RWE Power International has developed an in-situ ultrasonic inspection capability for the inspection of curved-entry blade roots. By creating an adaptable methodology that is applicable to most blade geometries, the technique can be relatively easily developed for other blade designs.
Individual blade geometric characteristics have a significant bearing on the actual inspection technique, especially the equipment required. When using scanning frames for in-situ inspection, the frames will be unique to each blade size and curvature. The ultrasonic inspection validation is carried out using a combination of computer modelling and testing of replica blades to maximize the efficiency of this stage while still providing a reliable proof of capability.

The resulting technique can detect a very high percentage of flaws in over 95 per cent of the volume of the blade root. This technique will save plant operators a significant amount of time and money compared with the removal of blades and will also provide the most thorough and detailed inspection possible.
ABSTRACT

The production of power is what engineers design gas turbines for, but unfortunately these machines generate more than just electricity. During normal operation the lubrication oil breaks down because of oxidation, high internal temperatures and mechanical stresses. This leads to the creation of sludge and varnish in the lubricant. Oil degradation products can severely affect the unit’s operational availability and reliability, leading to an increase in the its lifecycle cost.

Ansaldo Energia and Ansaldo Thomassen have developed a total lube oil management programme that includes diagnostic tools and efficient devices that enable turbine owners and operators to reclaim control over turbine oil issues. This five step lube oil management programme consists of: oil condition monitoring, oil cleaning, oil system improvements, oil condition control and lubricant selection.

For too long the condition of gas turbine oil has been analyzed using typical steam turbine lube oil test procedures. The principle of the operation of gas turbines differs largely from that of steam turbines, so there has to be a new focus when it comes to the choice of lubricant. Gas turbine lubricants require more specific oxidation and degradation-related tests to qualify oil samples.

Existing techniques to remove insolubles from oxidized and degraded modern turbine oils seem to be less effective. A new approach specific to gas turbine oil cleaning has led to the design of dedicated equipment. These fully PLC-controlled cleaners have remote monitoring capability, store operating data, perform online oil quality checks with controllable oil flow and oil temperature for optimized cleaning efficiency.

The application of the cross-port relief valve (CRV) plate instantly solves sludge and varnish problems in servo-valves and related systems. Measures to achieve acceptable minimum operating lives from gas turbine oils is also key in this programme. This paper provides users with practical steps, recommendations, tools and fixes to reduce as much as possible the effect on gas turbines of oil oxidation and degradation products. This paper refers only to products based on mineral oils, including mineral-based hydraulic oils as used in turbine control systems. Phosphate esters and other synthetic fluids show other problems, which may require a different approach.

1. INTRODUCTION

Heavy-duty turbines for the power industry can be divided into three groups: steam turbines, gas turbines and hydro turbines. This paper will discuss issues mainly related to heavy-duty gas turbines. It covers troubleshooting and provides remedies for problems with lube oil and systems.

From the perspective of lubricants, gas turbines were long considered to be similar to steam turbines. Know-how about, specifications for and field experience in steam turbine lubricants was extensive and adequate and the issues uncomplicated. The main problem with steam turbine lube oil was and still is water content, which can be easily dealt with by the application of a centrifuge or vacuum dehydration equipment.

For many years turbine users received periodical lube oil analysis reports that informed them about the quality of the lubricant which prevented the need for further specific attention. At the same time, however, there was a serious problem developing in the turbine oil that remained unobserved. Customers and operators were left unaware of upcoming trouble. How could this happen?

Gas turbines in the power industry are increasingly affected by operational and maintenance problems, which are directly linked to lube oil issues. Oxidation products from turbine oil, such as sludge and varnish, cause problems with various turbine components. Such problems will eventually lead to falling turbine reliability and availability.

In the early days of heavy-duty gas turbines, problems with lube oil and lube oil systems were limited. But the limits of lubricant capabilities were soon reached because unit power output, efficiency and thermodynamic stresses continuously rose. The result was that problems of all kinds began to surface.
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Ansaldo Thomassen

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Management and maintenance of lube oil
In today's gas turbines

Nigel Flenley
Conference Chair
The maintenance business and OEM support on this issue, however, did not yet recognize these problems. The usual solution then and, in many cases, even today, is to replace the lube oil. As we know now, this just means that the whole cycle starts all over again but even more rapidly. A snowball effect occurs that finally causes severe problems with turbine operation.

This paper provides guidelines on how to recognize these problems, how to prevent disturbances in operation and which tools to apply. Chemical processes which lead to oil oxidation are not described in detail in this paper. Sufficient literature on lube oil oxidation is available on the Internet, as the references at the end of this paper indicate.

We now focus on a strategy for controlling and correcting lube oil issues in gas turbines. This paper will cover oil condition monitoring, oil cleaning, oil system improvements, oil condition control and the selection of lubricant.

2. OIL CONDITION MONITORING

2.1 HOW TO DETECT TURBINE OIL PROBLEMS AT AN EARLY STAGE

If your maintenance programme for servo-valve repairs and replacements shows an upward trend, it is likely that your turbine has a serious lube oil or hydraulic oil sludge and varnish problem. Turbine oils face chemical, mechanical and thermal stresses. These stresses cause oxidation, which damages the oil molecules and forms so-called radicals.

New oil has a neutral composition and interacts minimally with its surroundings or oil-wetted parts. In contrast, damaged oil molecules in contrast have a polar signature and are attracted to other available polar materials such as metals and water.

The oxidation process produces by-products because of chemical reactions in the oil that include counter-action by anti-oxidant additives. These sub-micron products agglomerate into larger polymer-type structures depending on the type of base oil and additive package. Eventually this leads to the formation of insoluble particles such as sludge and varnish. Sludge, not to be confused with the milky substance that forms when oil is mixed with water, is a thick, sticky substance, polar by nature, which deposits easily on the metal surfaces of the oil piping system, for example servovalves, solenoids and, in the case of systems of low oil temperature, filters [see Figure 1].

CLICK TO VIEW FIGURE 1: CLOGGED LAST-CHANCE FILTER

An important property of sludge is its ability to change physical appearance as a function of time, flow and temperature. At an ambient temperature of around 20 °C and with very small or no oil flow, sludge molecules will over a certain period of time agglomerate and grow into larger particles that fall out of solution easily and settle on any available surfaces.

But when the temperature is increased to above 40–50 °C, depending on the type and condition of the turbine oil, the sludge polymers stay in solution or dissolve in the turbine oil again because the polymer substance breaks down.

Turbine oils that are heavily contaminated with sludge may even require heating to 70 °C or even 80 °C for the same effect to occur. Time is a crucial factor to be aware of in the sludge and varnish transformation phases. The change of state from insoluble to soluble is instant when the appropriate temperature of 40–50 °C is reached.

The opposite process of sludge particle agglomeration and precipitation requires much more time. Depending on the type of turbine oil and its condition this can range from 2 hours to 72 hours. Varnish is the more solid component. It is hard to remove from surfaces and is mainly found on the high-temperature parts of the system, such as bearing liners [see Figure 2].

CLICK TO VIEW FIGURE 2: VARNISH-COVERED BEARING LINER

Sludge and varnish particles are formed the moment the oil oxidation process begins but their presence remains largely undetected by standard oil tests. Even the ISO 4406 particle count fails to indicate the existence of such particles because of their small size, which is in the submicron range and has no noticeable impact on test results. The particles also pass through all gas turbine oil filters without a problem. A standard 5-micron nominal in-line full flow filter has a beta40 ratio of 200, which represents a 99.5 per cent filter efficiency for particles with a size of 40 microns or larger. Even typical depth filtration elements remove only particles in the particle size range of 1–5 microns and upwards.

Current standard turbine oil tests provide insufficient information and warning signals to notify gas turbine operators and owners of the imminence of a problem. Typical turbine oil analysis reports only include tests on viscosity, density, water and total acid number (TAN). Additional packages include supplemental tests such as particle count, rotating pressure vessel oxidation test (RPVOT) and ICP. But none of these tests reveal the true situation of the growing sludge and varnish problem.

Chemistry shows us that the oil oxidation process results ultimately in an increase in TAN. In the past when lubricants were formulated using oils, based on Group I and simple additive packages, TAN and viscosity tests were reliable indicators of trouble. Modern turbine oils may contain substantial quantities of sludge and varnish without a noticeable change in TAN and viscosity readings.

Because these traditional oil tests fail to detect sludge and varnish problems adequately Ansaldo has developed practical turbine oil...
Towards a safer world.

**Same game Better performance.**

At Ansaldo Thomassen we have some impressive solutions when it comes to servicing your industrial gas turbines. We have developed winning strategies for increasing performance & reliability, minimizing costs & risks, optimizing operations & maintenance and reducing emissions. Our portfolio of services includes upgrades, re-manufactured units, plus our own proprietary control & monitoring systems, all tailored to your specific requirements.

So, whether you require repair, field service, spare parts, upgrades, training or a long-term service level agreement, we believe we can get you to the finishing line faster. So why not get in touch to find out how well our capabilities match your requirements?

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analysis guidelines and revised test procedures. As a result, oil management programmes can be arranged and corrective steps planned well before the sludge and varnish problems influence gas turbine operation.

It is important to note that good quality oil sampling is of paramount importance. Test results, subsequent conclusions and recommendations depend directly on a good representative oil sample. Institutes such as Noria [1] provide good information on this topic.

2.2 PRACTICAL, USEFUL TURBINE OIL SAMPLE TESTS

2.2.1 MPG AND MPC TESTS

A very effective detection method for establishing the oxidation condition of the turbine oil is the gravimetric (MPG) or the colorimetric (MPC) patch test. Even without measuring insoluble weight or colour intensity a simple visual check clearly tells you whether there is a problem with the turbine oil or not. The test values allow quantification and selection of the proper action plan. Both MPG and MPC tests make use of the same membrane patch.

In the test, a turbine oil sample is drawn by vacuum through a patch membrane, typically with a diameter 47 mm and a small pore size of 0.45 microns.

For the MPG test the insoluble material on the membrane – in other words, of a size larger than 0.45 microns – is weighed on a precision scale and expressed in mg/litre. A practical warning level for insoluble contents of turbine oil is 20 mg/litre. A danger warning level would be around 50 mg/litre.

The MPC test on the same membrane results in a colour index number that represents the state of insoluble particles and the degree of oxidation of the oil. A standard for this test is specified in ISO 4405. One problem with this test is the complex characteristics of the sludge and varnish in the lube oil which directly affects test results. When the test is performed immediately after the taking of a sample, the results can differ completely from the results of the test performed on the same sample 72 hours later.

Time and temperature have a substantial impact on the outcome of the MPG and MPC tests, so Ansaldo defined a revised MPG and MPC test method. It was through extensive laboratory testing that the true physical characteristics of the sludge and varnish substance under a variety of conditions could be documented. This resulted in revised MPG and MPC tests.

The revised procedure performs dual patch tests on the same oil sample. For the first test, an oil sample is used that has been stored in a cool, dark place for a minimum of 72 hours. The test runs the oil at 20 °C.

A second test is performed on the same oil sample but now the oil is heated to 70 °C and stirred for at least three hours. Figure 3 provides examples of such tests.

CLICK TO VIEW FIGURE 3:
MPG-MPC TEST SAMPLES, COLD AND WARM

Figure 3 shows the test results for three oil samples. The upper patch membranes provide results at the low oil temperature and the lower patch membranes the results of the heated oil from the same sample. Patch weight and colour index differences of more than 50 per cent between the cold and warm tests are not uncommon and indicate the severity and state of the sludge and varnish. This ambient temperature patch test clearly shows that the turbine oil has a sludge and varnish problem.

Insoluble material gradually drops out of solution and deposits in the oil system, starting with certain areas of the lube oil and control oil system, where low flow and low temperature conditions occur. Such tests realistically mimic the condition of the lube oil inside the gas turbine. If there are few insolubles left on the membrane in both the cold and warm membrane patches then the oil does not contain enough sludge and varnish contaminants to cause serious problems (see Figure 4).

CLICK TO VIEW FIGURE 4:
MPG-MPC WARM OIL SAMPLE RESULT

If the cold patch contains deposits but the warm patch shows few signs of insoluble contaminants this indicates that the oil contains enough insolubles to cause sludge and varnish problems in certain systems that are subject to low flow and low temperature conditions. Figure 5 shows a low-temperature patch at 200 times magnification under the microscope. It shows severe contamination because of sludge and varnish formation.

CLICK TO VIEW FIGURE 5:
VISIBLE SLUDGE IN A COLD OIL MPG/MPC TEST

This dual-temperature MPG/MPC testing clearly proves that not only standard full flow filters but also depth filtration elements will have little or no effect in removing such particles from the turbine oil. Effective removal of sub-micron insoluble particles under normal operational conditions requires different equipment, which this paper will now discuss.

If both warm and low-temperature patches have a near identical colour index and weight of insolubles this indicates that no physical change of sludge and varnish particles occurs. In such cases, the sludge has already been transformed into a more steady-state solid substance called varnish. Varnish also causes problems because of deposition on metal surfaces. Since these contaminants are more solid
and larger in size than sludge at normal operating conditions it offers the option to clean the oil through specific depth filtration equipment.

2.2.2 ULTRA-CENTRIFUGE
In the ultra centrifuge test (UCT) a sample of oil is spun at high speed to generate g-forces above 15 000 g. Such forces make the solid particles separate from the oil and settle at the bottom of the test tube in a certain pattern depending on the quantity of insolubles in the oil (see Figure 7).

CLICK TO VIEW FIGURE 7A: UCT CLASSIFICATION PATTERN

CLICK TO VIEW FIGURE 7B: EXAMPLE OF A UCT TEST

To classify the deposits in the test tube a selection table is used. Each shape and density has a number, the more deposits the higher the number. This is a quick and easy test and does not require specific laboratory conditions or skills. On the other hand, results are not as exact as in the MPG and MPC tests.

2.2.3 RULER TEST
The Ruler test is also an effective diagnostic tool for testing turbine oil for remaining useful life. The test agrees with ASTM standard D6971-04’s linear sweep voltammetric test procedure, and is an instrument that measures the type and concentration of anti-oxidant additives in the oil and calculates its remaining useful life as a percentage of new oil.

The two most widely used anti-oxidant additives for turbine oil are phenols and amines. The Ruler test calculates useful remaining life based on the percentages of additives left in the oil. As the test is relative, the results are compared with a specific oil reference standard test made from a new sample of oil. It does not measure sludge and varnish concentrations, but provides helpful data that can be used to select the appropriate oil and define maintenance plans, as this paper will describe.

An interesting extra that the Ruler test provides is a test that presents graphical information about the presence of oxidation products in the oil. These are indicated by a steep tail at the end of the test curve. The reason for this is that the oxidation products in the oil react with the Ruler test solution. No exact data can be extracted from this, but together with other indicators it can confirm the existence of a possible sludge and varnish problem (see red curve in Figure 8).

CLICK TO VIEW FIGURE 8: RULER TEST RESULT

2.2.4 MICROSCOPIC EXAMINATION
Microscopic examination can be done both on the patch test membrane and on the turbine oil fluid, and a practical magnification range is 50–200 times. At this magnification the most important components that influence the sludge and varnish processes are visible on the membrane as liquid or amber spots. Apart from providing information on oxidation by-products it also shows other problems with the gas turbine, such as malfunctioning in-line filters. The presence of visible metal could indicate a possible bearing or gear problem. Further testing such as ferrographic analysis may be required to find the source of the wear particles (see Figure 9).

CLICK TO VIEW FIGURE 9: OIL LIQUID MAGNIFIED 200 TIMES: VISIBLE SLUDGE POLYMERS

2.2.5 PARTICLE COUNT
Sludge and varnish particle size depend on oil flow, oil temperature and time. During normal turbine operation these particles have submicron dimensions. Most particle counting is done according to the ISO 4406 or AS4059 standard. The minimum particle size detection range is 4 microns. This is far larger than the dimensions of the sludge polymers under normal operating conditions, and is why such particle counting is not effective in detecting the presence of sludge and varnish in the turbine oil.

It is helpful to monitor the general cleanliness of the turbine oil and to detect changes in the amount of wear particles generated that are present in the turbine oil. An increasing number of on-line particle counting devices are becoming available on the market and are increasingly applied by manufacturers and service providers to continuously monitor the oil. Certain types of equipment can benefit from such devices, depending on the typical wear pattern of the equipment and the presence of extraneous dirt, which can also cause problems.

Field experience has shown that typical heavy-duty gas turbines in power industry applications rarely show large quantities of extraneous particles in the oil. This justifies the installation of on-line particle counting sensors. The in-line filtration capacity of a typical heavy-duty gas turbine is sufficient to remove large particles from the oil effectively, either those arising from wear or from outside the unit, or those which have formed because of maintenance activities. The in-line filtration capacity can keep particle concentration in the oil low. Frequent particle counting is good practice for monitoring the oil and determining trends in its cleanliness. On-line sensors are not effective when it comes to monitoring sludge and varnish formation in turbine oil. Their main effect is to observe the quality of the filtration system.

3. OIL CLEANING

3.1 REMOVAL OF INSOLUBLE CONTAMINANTS BY APPLICATION OF IMPROVED ELECTROSTATIC OIL CLEANERS
We have seen that typical mechanical filtration is limited in its ability
to keep oil free from oxidation by-products. It is time to look for solutions that can effectively remove sludge and varnish from the oil. Sludge and varnish particles in the turbine oil are of submicron size during normal operating conditions and these cannot be removed via traditional mechanical filters. We have seen that even depth filtration has its limitations when it comes to removing submicron particles.

Most depth filtration elements are made of cellulose, which has a certain natural polar signature. It is through this polarity that sludge and varnish particles will be trapped in the elements over time. To clean turbine oil on a large scale and to remove large quantities of sludge and varnish under normal operating temperatures requires more effective equipment. Originally designed for other applications, the electrostatic separation principle has proved to be very effective in removing submicron sludge and varnish particles from the oil without affecting or removing the additives that are in it.

**CLICK TO VIEW FIGURE 10: ECC-D4**

Electrostatic separation is based on the principle of creating an electrostatic field between a system of electrodes. A dielectric material separates these electrodes and directs the polar contaminants in a constant flow of oil towards the electrodes. The force pulling particles towards the electrodes only affects polar material in the oil, which means sludge and varnish particles. To increase the cleaning effect a non-conductive material of a specific shape is installed between the electrodes so more sludge and varnish particles can be removed than by electrodes alone.

The typical electrostatic oil cleaner was designed for systems that contain hydraulic oil and other Group I mineral oils. The application of these cleaners in such systems has been successful. With turbine oils now gradually becoming Group II-based as a response to the growing population of gas turbines with serious sludge and varnish problems, the effectiveness of this oil cleaner appears to be dropping.

On a number of projects, electrostatic cleaners have had disappointing results. This is why Ansaldo began its improved electrostatic oil cleaner project. This development project has produced a new generation of oil cleaner called the ‘electrostatic cooled cleaner’ (ECC). A prototype unit has been in operation since October 2008 in a power plant in northern Italy. The main features of the ECC are:

- Full PLC control
- Adjustable oil flow
- Adjustable high voltage
- Adjustable oil temperature
- Operational and alarm data storage

**CLICK TO VIEW TABLE 1: ECC DATA SHEET**

Under a second phase of development of the ECC, the cleaner will include an oil quality sensor that measures oil parameters online and feeds them back into the ECC control system to optimize the cleaning effect.

The first ECC operating results are positive. In a nine month operational test on a 12 000 litre oil reservoir in an Ansaldo V94.2A gas turbine unit the oil’s insoluble content dropped by about 50 per cent.

Under a third phase, development will focus on optimizing the cleaning chamber internals. As a result the ECC system will be able to remove sludge and varnish effectively from modern turbine oils under all operating conditions as experienced by high-performance heavy-duty gas turbines.

**CLICK TO VIEW FIGURE 11: ANSALDO TVA SYSTEM CONNECTION DIAGRAM**

**4. LUBE OIL SYSTEM IMPROVEMENTS**

**4.1 CRV PLATE ELIMINATES THE PROBLEM OF THE STICKY SERVO-VALVE**

**CLICK TO VIEW FIGURE 13: CRV PLATE APPLICATION ON 7F IGV ACTUATOR**

It is good practice to frequently look closely at the quality of turbine oil and to take measures that prevent serious problems from occurring. Oil samples should be tested in the way we have earlier described. This gives a clear indication of the extent of oil oxidation.
Electrostatic oil cleaning can be made highly effective but it is still a process that takes considerable time. As a rule of thumb, the gas turbine oil reservoir content must be cycled through the ECC at least 200 times to achieve substantial removal of sludge and varnish. Based on our ECC-D16 with a capacity of 16 litres/minute and a typical turbine reservoir volume of 6000 litres, a complete cleaning cycle takes between 50 and 80 days. Because sludge and varnish production in the turbine oil continues as long as the precursors are active, turbine components such as servo-valves are affected. Therefore Ansaldo has designed a smart device that prevents and solves the problem of a ‘sticky’ servo-valve.

The CRV plate activates servo-valves in standby operation or discontinuously operates parts of the control system. The plate is a purely mechanical device that is installed between the base of the hydraulic actuator and the servo-valve (see Figure 14).

**CLICK TO VIEW FIGURE 14:**
**CRV PLATE APPLICATION ON GAS FUEL SPLITTER VALVE**

As we have already discussed, the physical state of the insolubles of sludge and varnish depends greatly on oil temperature, time and oil flow. In control systems with discontinuous action the oil flow is close to zero, which allows the particles of sludge and varnish to agglomerate into larger polymer structures. When sufficiently large these fall out of solution and settle on the metal surfaces in the system. How does the CRV plate prevent this from happening?

The CRV plate is a block that contains a configuration of ports that is identical to that of the servo-valve it is connected to. The current version of the CRV plate also includes two adjustable needle valves (see Figure 15).

**CLICK TO VIEW FIGURE 15:**
**ARRANGEMENT OF PORTS AND VALVES IN THE CRV PLATE**

By opening the correct needle valve according to the installation instructions an oil flow is created between the selected actuator port and the drain of the system. This oil flow acts as if the actuator has a leak. This makes the control system counter this action by supplying more oil to the actuator to keep the specific valve or actuator position to the control system. The plate is a purely mechanical device that is installed between the base of the hydraulic actuator and the servo-valve (see Figure 14).

**CLICK TO VIEW FIGURE 16:**
**SCHEMATIC OF IGV SYSTEM WITH CRV PLATE APPLICATION**

Field installation practice has resulted in a simple procedure for the setting of the CRV plate needle valve: monitor the temperature of the oil supply line to the actuator by hand. The preferred oil supply line temperature should be at least 45 °C or as close as possible to the actual oil tank temperature of the turbine. The effect of the CRV plate when installed and properly commissioned is instant. The precipitation of sludge and varnish in that part of the control system stops immediately.

In long-term CRV plate applications on gas turbines that were experiencing seriously sticky servo-valve problems, from the moment the CRV plate was installed the systems no longer required the replacement of the servo-valve.

Extensive tests to validate the safe operation of the device have showed that under maximum oil flow conditions the effect on the actuator response is marginal. In its normal expected operating range the CRV plate does not change the response of the actuator. Table 2 shows data from measurements taken during such tests on a 7F gas turbine in which the CRV plate was installed on the IGV actuator.

**CLICK TO VIEW TABLE 2:**
**TEST DATA FROM THE CRV PLATE COMMISSIONING**

<table>
<thead>
<tr>
<th>Test Condition</th>
<th>CRV Plate Installed</th>
<th>CRV Plate Not Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actuator Type</td>
<td>Response Change</td>
<td>Response Change</td>
</tr>
<tr>
<td>Gas Turbine</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

5. TURBINE OIL CONDITION CONTROL

Turbine oil oxidation and degradation is influenced by several factors concerning the turbine and surrounding it. The speed with which it occurs depends on a number of factors. Each can be a single effect, but mostly the problem will be a combination of:

- Gas turbine type and application
  - Presence of a load gearbox
- Lube oil system design
  - Lube oil and hydraulic control system design
  - Oil reservoir volume
  - Oil flow
  - Oil pump capacity versus system flow
- Gas turbine operating schedule
- Turbine oil type
- Oil conditioning measures

**CLICK TO VIEW FIGURE 17:**
**EVOLUTION OF GE GAS TURBINES**

5.1 GAS TURBINE TYPE AND APPLICATION

Detailed reviews which searched for a correlation between various heavy-duty gas turbines and turbine oil sludge and varnish problems...
found that units whose lube oil and hydraulic control systems use the same lubricant are more sensitive to the development of serious sludge and varnish problems than gas turbine units with separate systems. Among gas turbine units with combined systems, different effects clearly depend on frame size. The presence of a large load gearbox has a substantial effect on oil oxidation. In typical high-capacity load gearboxes (greater than 40 MW) the rise in lube oil temperature from inlet to outlet can be as much as 50 °C, excluding peak temperatures in bearings at the load point and in the gearmesh area.

Lube oil in a gearbox also has an important cooling function. Typically 1–2 per cent of the power output is lost through friction in the load gearbox, which causes heat loss. For a 40 MW gearbox this amounts to an average heat loss of 600 kW, which has to be removed by the oil. This is why a load gearbox is the biggest lube oil consumer in the gas turbine system. It typically consumes between 50–60 per cent of total oil flow.

The split in total oil flow to the gearbox is 25 per cent to the bearings and 75 per cent to spray the gears to allow lubrication and cooling. It is the spraying of the oil that accelerates the lube oil oxidation process.

The gearbox internal cavity is saturated with a dense oil mist of small droplets. All the droplets together represent an enormous oil oxidation surface. The combination of high temperature, large surface contact area and turbulent air motion caused by the spinning gears accelerates the oxidation process of the oil considerably. The oil is also exposed to enormous mechanical stresses. In a typical gas turbine load gearbox, the gear-mesh velocity is close to the speed of sound. The oil, while being squeezed between fast moving teeth flanks, must lubricate and cool under extreme conditions. It is therefore good maintenance practice to inspect the teeth surface condition and colour when the unit is shutdown. While inspecting the gear teeth surface it is important to also look for brown or black discoloration and the presence of sludge and varnish deposits inside the gearbox. This is a good indication of the condition of the lube oil.

Users of gas turbines with separate oil systems most likely become aware of the presence of sludge and varnish problems only when the unit is down for major overhaul and turbine bearings are opened up for inspection (see Figure 2).

5.3 OPERATION OF GAS TURBINES

The operating regime of the gas turbine has a high influence on oil degradation. Decades ago gas turbines mainly operated in continuous mode at baseload. Due to globalization and liberalization of the energy market and the growing number of sustainable energy sources, more and more gas turbines are now operating in peak-shave or back-up mode. Large gas turbine units that are on standby most of the time serve a single purpose: instant supply of power. Failing to meet this requirement can lead to severe contract penalties and serious upsets in the power grid.

Oil flow, oil temperature and time determine whether sludge and varnish in the oil will cause the gas turbine serious problems. These are also precisely the factors that are influenced by the operating conditions. In general, gas turbines that operate continuously experience different lube oil problems than units that operate in a cyclic mode: high-temperature varnish rather than sludge. Cyclic units see more problems concerning sludge, as is the case with IGV actuators and related systems and devices.

5.4 CONDITION CONTROL

In too many cases turbine oil degradation develops to the point at which oil replacement is inevitable. Unfortunately it is still common practice to replace the old oil with new turbine oil without following procedures that give the new lubricant a good start in life.

Draining of the old oil, flushing the system and filling the unit with new turbine oil seems a simple plan but field experience often shows that there is more to the issue. If old oil caused serious sludge and varnish issues in a gas turbine unit, fresh oil will most likely soon show similar signs. As a rule of thumb, after each oil replacement without specific remedial action the service life of new oil can fall by as much as 25 per cent.

In one case in which a serious problem arose because of the turbine oil the operator stated that the lubricant was only renewed 18 months previously. The oil contained large quantities of sludge and varnish, and the anti-oxidant additives were almost completely depleted. Records showed that the unit had a long history of oil problems and subsequent replacements. This is why the practice of dump and replace is not recommended. The recommendation is to follow bleed and feed guidelines instead.

A bleed and feed programme is based on the condition of the lube oil condition and aims to remove a certain percentage of old oil and replace it with new.
A general rule for the bleed and feed programme for continuously operated gas turbines is for about 10 per cent of the unit's oil volume to be replaced on an annual basis. If the oil condition dictates that large quantities of oil be replaced the advice is to split this procedure into more sessions to prevent the disturbance of the chemistry of the lube oil. Another recommendation is to consult the oil manufacturer in such cases.

In preparation for the replacement of the turbine oil the advice is to clean the lube oil as much as possible to create an optimum environment for the new oil. Various actions can help here. If the replacement of the oil is well planned in advance the first step is to install an ECC oil cleaner to remove contaminants, sludge and varnish, not only from the old oil but also from the oil system. The next step, before the replacement, is to add 5–10 per cent of special oil to increase solvability, which enhances the dirt-containing capability of the oil.

6. TURBINE OIL SELECTION

6.1 TURBINE OIL TYPE

The selection of the proper turbine oil and maintenance of its condition are the key factors that allow it to endure the severe mechanical and thermal stresses it will experience.

At first, only one type of turbine lubricant was available: lubricants based on Group I oil types. These oils have limited oxidation resistance, which can impact their operating lives. Another property of these lubricants is their solvency capabilities. They keep contaminants in solution longer than modern turbine oils are able to. The rapid rise in more difficult load conditions in modern gas turbine units in recent years has demanded the use of more modern turbine oils. Lubricant manufacturers switched to oils based on Group II - which are severely hydro-cracked and hydro-treated oils – and new additive packages to increase lube oil oxidation resistance. Soon the turbine oil market discovered that high values for RPVOT numbers were the solution to lube oil problems.

RPVOT is a standardized way of measuring the oxidation reserve of the oil. In a modified form it represents the oil's capability to handle thermal and chemical stresses in time. The understanding was that the higher the number the better the oil. Creative chemistry produced additive compositions that gave very high RPVOT values. It was not uncommon to find turbine oils with values exceeding 2000 minutes. However, this was with TOST results of greater than 20,000 hours, which questions the accuracy of the test.

But field experience showed a downside: a number of modern turbine oils based on Group II experienced substantial problems with sludge and varnish, primarily related to the anti-oxidant additive packages that were used.

Certain combinations of amines substantially contributed to these phenomena. The lube oil testing of the time was unable to measure sludge and varnish formation let alone warn about the imminent problem of its formation. So another effect of the use of oils based on higher groups has been that there have been more cases of the less effective electrostatic method of cleaning. More research is needed to find the root cause of this problem.

7. FINAL ADVICE ON OIL STORAGE

This paper would not be complete without recommendations about the proper way to store oil. Oil storage is often neglected. Lubricants are increasingly packaged in transparent IBC containers. This works fine for a quick visual check of container content but at the same time it introduces a serious problem for new oil. UV radiation in normal daylight rapidly affects the condition of the oil. Sunny conditions worsen the situation.

Experiments with fresh turbine oil samples have shown that they can lose up to 100 per cent of their anti-oxidant additives in 3-4 months when exposed to normal daylight. Proper storage of lubricants is vital to maintain the freshness of the oil. So store lubricants in a cool, dark and dry place.

CLICK TO VIEW FIGURE 18:

AN EXAMPLE OF HOW NOT TO STORE YOUR TURBINE OIL

8. CONCLUSIONS

In the past the use of available best practices and standard lube oil testing allowed turbine oils to be monitored and maintained without problems.

Increased turbine output power and increased thermal load on new generation gas turbines has led to a dramatic increase in lube oil problems, caused mainly by sludge and varnish. Today’s turbine oil technology and maintenance practices have evolved from simple, straightforward practices that were based on steam turbines to an approach that is more specific to a gas turbine machine type, application and operation.

This paper has presented gas turbine owners and operators with a series of practical steps, recommendations, tools and fixes to maximize unit availability and reliability by reducing the effects of turbine oil degradation, such as sludge and varnish, in heavy-duty gas turbines.
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Power Diagnostic Service for Service Customers Using Speciality Monitors

ABSTRACT

Availability, flexibility and reliability are the key words when it comes to successful power generation in the European market. Deregulation and liberalization have made it increasingly important to know the exact condition of a power plant's components. Siemens has developed several expert systems – the so-called speciality monitors – to enable service customers to gather more information about the condition of their steam turbine, generator and high-voltage components.

These speciality monitors work as stand-alone solutions and can monitor a specific component continuously. But the greatest benefit can be achieved by connecting these monitors to a superordinated diagnostic platform. This allows data from the speciality monitors to be combined with the plant and process data of the digital control system. By correlating all of this information, the source and cause of abnormal behaviour can be more easily identified, and corrective or preventive actions can be planned, such as a shutdown for local repairs.

The objective of Siemens’s remote monitoring services is the maintenance of high plant reliability through the detection of operating anomalies long before they would normally be observed by plant personnel. In general, the remote monitoring methodology is to watch and analyze long-term trends in operating data. This is carried out by using sophisticated analytical software and technical and engineering staff that specializes in such analyses.

The first Power Diagnostics® data acquisition system was commissioned in 1998 and about 400 units are now monitored worldwide. Power Diagnostics monitors gas turbines, steam turbines, generators and combined-cycle balance-of-plant equipment. On detection of an issue, Siemens engineers prepare a report summarizing the details of the issue, possible causes and suggested actions. This report is then sent to technical and regional service managers, who can forward and discuss the report and possible courses of action.

1. INTRODUCTION

Developments in recent decades have led to major improvements related to power plant efficiency. New plants with increasing process temperatures and pressures have been installed and commissioned using state-of-the-art components to reduce the overall losses in the process.

In addition, many existing plants have been able to be modernized with the latest technology, such as highly efficient turbine blades. This has led to the creation of ‘green megawatts’ by producing additional power without an increase in fuel consumption.

Next to the highest possible efficiency, power plants are facing a new requirement from the market. Renewable energy, such as wind and solar, is of increasing importance and is gaining a noticeable share of the market in the power generation business. Renewable energy, especially wind power, is not easy to forecast.

The nature of wind means it is completely out of the control of utilities. Therefore fossil and nuclear power plants will face a severe change in their operational requirements. Renewable energy, which is volatile, will supply the grid to its fullest extent and the remaining power demand – which is now less predictable and fluctuates more than in the past – has to be covered by existing power plants.

Therefore in the years to come flexibility will be the major requirement of power plants, particularly those fired by fossil fuels but nuclear plants too.

This will lead to the need for a greater number of startups, which will also have to be faster. It will also lead to more frequent partial load operation with fast load ramps to increase or decrease power output.

Equipment manufacturers are developing flexible products that will help to fulfill the changing needs of the market, and new plants will be designed according to more flexible
load regimes. Also, existing plants will have to be checked and improved to be able to operate with greater flexibility.

Close cooperation with equipment suppliers will allow the optimization of plant flexibility without making compromises when it comes to reliability. This paper will present monitoring and diagnostics technology, which is a key way of avoiding the overloading of plant equipment.

Siemens has developed several expert systems, the so-called speciality monitors, to allow a deeper judgment to be made of the condition of, for example, steam turbines and generators. The aim of this paper is to provide an overview of speciality monitors and show what additional benefit can be gained when they are combined with a diagnostic service. Doing this brings the expertise of equipment suppliers into the effort to detect abnormal behaviour at the earliest and provides recommendations for actions.

2. SPECIALITY MONITORS FOR DIAGNOSTICS FOR PLANT EQUIPMENT

In addition to the monitoring of the operation of a power plant, the representation of which is generally displayed in a control room, speciality monitors provide additional insight into the behaviour or condition of individual plant components.

Figure 1 shows the rotor train of a single-shaft combined-cycle power plant that uses some of the special monitoring and diagnostic systems developed by Siemens.

CLICK TO VIEW FIGURE 1:
SIEMENS SINGLE-SHAFT ROTOR TRAIN WITH SPECIAL MONITORING AND DIAGNOSTIC SYSTEMS

Most of the diagnostic systems shown in Figure 1 are referred to as ‘speciality monitors’ and are installed only on special request, often after many years of the monitoring of aging equipment.

Others, more often, are implemented from the first day of operation of the plant. In the case of gas turbines examples are diagnostic monitors used in many control rooms in new plants.

This paper now presents some of the special monitoring and diagnostic systems shown in Figure 1, and shows what benefit can be gained from their application.

A foreign object detection (FOD) system, as shown in Figure 2, monitors a plant continuously to prevent the potential loss of combustion chamber components, such as ceramic heat shields, to protect turbine blades and vanes from the damage that foreign objects cause. Furthermore, such a system detects blockages of the first row of vanes, which also prevents consequential damage to turbine blades and other vanes. An FOD system is acoustic and is based on the analysis of structure-borne noise and the detection of burst signals produced by the impact of loose parts in the chamber or on the guide blades of the turbine.

Eight accelerometers are mounted at different positions on the outer shell and the carrier of the turbine guide blades. Their signals are picked up near the turbine, digitized and transferred to the central FOD system’s power control centre (PCC). A special analysis continuously runs in the frequency and time domains to monitor burst signals even if their amplitudes are lower than the normal background signal in the time domain. A special algorithm for the FOD system was developed to classify events and to generate appropriate warnings or protection alarms within a specified time frame to avoid turbine damage:

• Warning – evaluation is performed by Siemens specialists
• Emergency trip – if blocked channel is confirmed

In the case of an event, Siemens is informed automatically and the system provides the necessary detailed data. Specialists further analyze the event to ensure safe operation.

CLICK TO VIEW FIGURE 2:
ACOUSTIC MONITORING SYSTEM

The next example is a speciality monitor that measures the tip vibrations of the steam turbine last-stage blades [1]. This module may have special importance in plants that operate in a more flexible manner because low load operation may create higher stresses in the blades than full load operation. This is due to the flow field in the LP blading, which is more complex in part load because of the pressure variations from blade hub to tip.

The blade-tip vibration measurement system is typically applied to the last-stage blade row. It monitors all blades of the circumference.

As Figure 3 shows, the blade tips pass two sensors. Signals from these sensors and the shaft mark signal allow the vibrational displacement of the blade tip in the circumferential direction to be determined. The system is able to display the vibration of individual blades, as well as the total vibration of all blades by using colour to show when certain vibration thresholds have been passed (see Figure 3).

CLICK TO VIEW FIGURE 3:
BLADE TIP VIBRATION MONITORING AND BLADE STRESS DIAGNOSTIC SYSTEM

The operator is informed when a defined vibration level is reached which is still low enough to avoid life consumption of the blade. The operators can then change operational parameters such as condenser pressure or power to prevent vibration reaching a level that may damage the blades. If this is not possible the speciality monitor evaluates the life consumption of each individual blade and indicates whether a crack is expected.
Another speciality monitor relates to generators and other high-voltage components. SIEMENS HF 10–2 detects partial discharges and gives power plant operators advance notice of possible damage to insulation [2, 3]. Increased partial discharge activity can occur in many situations, especially when insulating systems are aging or damaged. These partial discharges bridge a portion of the high-voltage insulation and their high-frequency nature can be detected. Impending insulation damage often appears as continuously increasing partial discharge phenomena and can therefore be detectable in advance by continuous monitoring using radio frequency measurement methods (see Figure 4). The system evaluates the propagation times of partial discharge impulses to allow insulation faults to be localized.

3. SERVICE CONCEPT FOR SPECIALITY MONITORS

Our final example of speciality monitors allows the condition of generator stator end windings to be evaluated [4]. The vibrations of the end windings can increase over time because of material aging, heating up, cooling down and loosening. A particular cause of the loosening is grid disturbances that involve incorrect switching operations and lightning strikes. Unusually high vibration levels can result in the loosening of the end winding assembly and the formation of friction dust. Figure 5 shows the optical accelerometers and typical installation locations of a comprehensive monitoring system which continuously records the levels of end winding vibration. An evaluation of this trend data enables the dynamic behaviour of the end windings to be determined. This means the analysis and assessment of any changes in the behaviour can go ahead. Proactive monitoring using this system can help improve generator reliability and availability, as well as reduce the potential for system downtime.

CLICK TO VIEW FIGURE 5: FIBRE OPTIC ACCELEROMETERS TO MONITOR GENERATOR STATOR END WINDING VIBRATION

4. SERVICE CONCEPT OF POWER DIAGNOSTICS CENTRES IN GENERAL

The information presented in this part of the paper will cover Power Diagnostics services in general. It will also, through an example, show the advantages of combining speciality monitors and the Power Diagnostics Centre approaches. Hardware failures, instrumentation malfunctions or control logic issues may result in the failure of startups, engine trips, output of power and heat rate degradation. The objective of Siemens’s remote monitoring is the maintenance of high plant reliability through the detection of operating anomalies long before they would normally be observed by plant personnel.

CLICK TO VIEW FIGURE 6: THREE-LEVEL SERVICE CONCEPT FOR SPECIALITY MONITORS

The second level makes use of the know-how of equipment suppliers, as shown in Figure 7. A Power Diagnostics service contract is signed between the customer and the equipment supplier to use the engineering expertise of the supplier in the process of judging the behaviour of the plant components.

CLICK TO VIEW FIGURE 7: SERVICE CONCEPT LEVEL 2 – SUPPLIERS’ EXPERTISE IS USED AT DEFINED INTERVALS

The expert-based diagnostics takes place at defined intervals, perhaps monthly or quarterly. The data from the speciality monitor, including some operational values from the plant controls, are sent to Siemens via CD, DVD or a network data exchange. The third level of the service concept for speciality monitors uses a daily Power Diagnostics service. Data from the speciality monitors or a superordinated diagnostic platform are sent with a certain set of predefined operational data to the Power Diagnostics centre. This allows the use of advanced Siemens diagnostic tools to correlate all available plant data and analyze trends and unexpected deviations with the help of the expert network (see Figure 8).

CLICK TO VIEW FIGURE 8: SERVICE CONCEPT LEVEL 3 – USE OF A DAILY POWER DIAGNOSTICS SERVICE

"THE OBJECTIVE OF SIEMENS’S REMOTE MONITORING IS THE MAINTENANCE OF HIGH PLANT RELIABILITY THROUGH THE DETECTION OF OPERATING ANOMALIES LONG BEFORE THEY WOULD NORMALLY BE OBSERVED BY PLANT PERSONNEL."
The first Power Diagnostics data acquisition system was commissioned in 1998 and around 400 units are now monitored worldwide. Power Diagnostics monitors gas turbines, steam turbines, generators and combined-cycle balance-of-plant equipment.

4.1 BENEFITS OF EARLY DETECTION
There are many factors behind the decisions on which corrective actions to take after a diagnostics finding. Some of the factors that must be considered are the plant’s dispatch requirements, hardware costs, labour costs and availability, contractual arrangements, and safety. The early detection of abnormal operating conditions that Siemens’s remote monitoring provides enables the operator to take a more proactive approach when making an informed decision. This can:

- Help to reduce the number of trips and failed starts by:
  - Catching intermittent or failing instrumentation before the controls respond
  - Early detection of hardware issues
- Reduce the duration of outages by: performing inspections that are focused
- Gain a better understanding of the support that is needed (what parts, what tools, what personnel)

4.2 DATA ACQUISITION
Power Diagnostics installs and maintains a data acquisition system at the site. The system is connected to the Power Diagnostics Centre (PDC) demilitarized zone (DMZ) through a secure virtual private network (VPN) with a router/phone connection as back-up. The PC-based data acquisition system is passively connected to the control system, receiving data from the I&C system along a one-way data highway with no feedback to the site’s I&C system (see Figure 9).

Selected signals from the plant control system are transferred and stored in real-time in the Power Diagnostics data acquisition system on-site. At midnight, the data acquisition system closes the daily data file and automatically transfers it over the VPN to the DMZ. Dead bands, cycle times and event-based recording rates are implemented in the site data acquisition system to maximize the quality and minimize the quantity of data transferred.

CLICK TO VIEW FIGURE 9:
DATA AND INFORMATION HANDLING IN POWER DIAGNOSTICS

The site-based data acquisition system also has real-time data viewing capabilities and graphing tools that can be used locally by plant personnel. Training is available by the Power Diagnostics engineering technician during installation of the system.

Power Diagnostics software is based on standard, commercially available products. The user interface is based on Win CC and has the familiar Windows ‘look and feel’. Standard tools for data management, archiving, trending and alarming are an integral part of the system frame.

4.3 DATA PROCESSING
The Power Diagnostics Centre is manned 24/7 by an engineering technician who uses a variety of tools to track the progress of the data transmission and the health of the data acquisition system. The technician answers the 24/7 toll free phone line and contacts either the Power Diagnostics on-call engineer or the I&C on-call engineer depending on the nature of the call.

Once the raw data arrives at the Power Diagnostics Centre, it is processed through an empirical, system-modelling tool called Power Monitor and an artificial intelligence rule base called PDR.

Detecting subtle deviations in the analogue sensors in the variability of normal operation – well within the existing control threshold alarm limits – enables early recognition of abnormal equipment behaviour. An advantage to this generic monitoring technique is that it can be applied to a variety of instrumented equipment. Out-of-date calibrations, missing or incomplete tag suites and bad sensors can be accommodated with the modelling tool.

System Modelling: Several models are built on basic relationships within the power generation equipment. During an initial ‘learning period’, baseline operating conditions or ‘normal operation’ for each model is established. The model’s ability to predict the ‘expected values’ based on the training data will be the basis for setting the warning limits. For example, if a combustion model can predict a turbine outlet temperature within ±2 °C during a normal operation, the limit is set at ±5 °C. So if that temperature deviates from the expected value by more than 5 °C a warning is issued.

Artificial Intelligence (AI) Rule Base: The rule base takes into account all deviations from expected and any unusual signal characteristic changes that it detects. It generates a malfunction to assist the engineer in a diagnosis.

By far the most critical step in the analysis is the review of the processed results by the Power Diagnostics engineer. One of the distinct advantages of having the Siemens remote monitoring service is the expertise readily available to find the root cause of anomalies and provide recommendations for corrective actions.

If the Siemens Power Diagnostics engineers are faced with new or unusual issues, they can quickly make the data available and easily consult one of many specific component and design engineers located near the remote monitoring centre. These engineering specialists can bring extensive expertise to the evaluation of operational or hardware issues.

4.4 INFORMATION FEEDBACK
On detection of an issue, Siemens engineers prepare a report summarizing the details of the issue, possible causes and suggested
actions. This report is then sent to the technical and regional service managers, who can forward and discuss the report and possible courses of action with owner personnel.

Power Diagnostics Services also includes a 24/7 hotline for more real-time, reactive support. Feedback is typically a call back to the control room or source of the call, and the issue is documented with a report.

5. COMBINED STRENGTH OF SPECIALITY MONITORS AND POWER DIAGNOSTICS SERVICES

Keeping in mind the capabilities of the different speciality monitors and the benefits of the Power Diagnostics Centres, it is obvious that combining these leads to an even more powerful diagnostics solution. As soon as the specialty monitors are connected to the PDC, the following additional features are available:

- Daily monitoring and analysis of trends
- Correlation with operational data
- Automatic and fast response in the case of abnormal behaviour
- Fast expert network reaction in the case of urgent issues
- Recommendations for scheduled actions
- Implementation of solutions remotely or onsite

6. DIAGNOSTICS EXAMPLE: DETECTION OF PARTIAL DISCHARGE IN A COMBINED-CYCLE POWER PLANT

The following example shows perfectly the benefits of expert-based diagnostics in combination with the use of speciality monitors and the additional advantage gained from the Power Diagnostics Centre services.

The trend curves of the partial discharge monitor of the four measuring points near the generator (GL1, GL2, GL3 and N) repeatedly exhibited pronounced increases in partial discharge amplitudes (nC) for a short time (see Figure 10). The overall behaviour did not change over about five months.

CLICK TO VIEW FIGURE 10:
PARTIAL DISCHARGE TRENDS WITH REPEATEDLY PRONOUNCED INCREASES

A detailed look at the trend curve shows that these sporadic increases occur particularly during part load operation of the generator and, in some cases, exceeded the alarm thresholds for maximum partial discharge level.

Using expert knowledge the data were investigated in more depth. This involved a look at the real-time signals of the partial discharges (see Figure 11). These were found to be typical of external discharges because of a local increase in field strength. In this case the experts expected an energized sharp tip at which partial discharges arc in the air to an opposite large area potential, most probably the ground. The highest amplitudes were measured on phase L2. At Phases L1 and L3, the amplitudes were judged to be crosstalk from L2.

CLICK TO VIEW FIGURE 11:
EXPERT-BASED DIAGNOSTICS OF PARTIAL DISCHARGES USING REAL-TIME SIGNALS

Using the propagation-time measurement, the root cause was narrowed down to be in the area of the generator (see Figure 12).

CLICK TO VIEW FIGURE 12:
LOCATION OF MEASUREMENT POINTS AND PARTIAL DISCHARGES

It was possible to exclude mechanical causes in the end windings from the list of potential root causes because a comparison showed no correlation between end winding vibrations with the increased partial discharge levels (see Figure 13). The experts also judged the risk for the continued operation of the plant to be small following further evaluation of the specialty monitor.

The next planned outage was used to conduct further onsite measurement and to finally detect the root cause – in line with the experts expectations. High partial discharge single pulses were detected at the stator winding with an off-line PD-measurement. The source was identified as the main bushing which was than replaced by a spare bushing of the same type during the outage.

CLICK TO VIEW FIGURE 13:
COMPARISON OF PARTIAL DISCHARGE AND END-WINDING VIBRATIONS

To summarize this example, the trends in the partial discharge measurements showed higher discharge levels, especially at measurement location GL2, close to the generator.

Detailed analysis by the experts was able to narrow down the potential causes of the increased partial discharge levels by looking at the characteristics of the real-time signals and using propagation-time measurements. A comparison with the end winding vibration monitor then helped to exclude the end windings as being the root cause.

This example shows how each speciality monitor alone may play an important role in the power plant. The combination of more than one monitor and the correlation with operating data further increases the number of insights that can be gained about the conditions of components.

Combined with a daily service from the Power Diagnostics centre the path is well laid out to detect deviations early and to mitigate
threats to the reliability or availability of the power plant.

7. FURTHER SCOPE FOR DIAGNOSTICS
This paper focused on the Power Diagnostics services for power generation equipment, especially turbines and generators. However, the use of diagnostics is also beneficial for other products in the energy portfolio, from primary energy to power distribution (see Figure 14). The wind energy and oil and gas industries use diagnostics services to keep the availability and reliability of components at their highest.

CLICK TO VIEW FIGURE 14:
FURTHER SCOPE FOR DIAGNOSTICS SERVICES

8. CONCLUSION
The demand for flexible power generation in power plants will lead to an increasing need for monitoring and diagnostics for power plant components. Siemens has developed several speciality monitors and service concepts to support operators according to their needs.

If the power producer chooses the option for the closest cooperation between itself and Siemens – the daily service from the Power Diagnostics centre – the maximum insight into the condition of components can be gained and deviations from normal behaviour can be detected early.

Siemens Energy proposes to take this route to target the highest availability and reliability of power plants and other Siemens Energy products – from primary energy to power distribution.
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RENEWABLE ENERGY
WORLD EUROPE
Drilled Concrete Monopile Foundations for Offshore Wind Farms

ABSTRACT
A wind turbine park called Kriegers Flak could be built in the south of the Baltic Sea. A new offshore foundation concept has been developed called the drilled concrete monopile. The general principle consists of the installation of a prefab concrete monopile using a vertical drilling method. This method is based on horizontal tunnel drilling methods used onshore. Concrete monopiles have been designed for 3.6 MW and 5 MW wind turbines in a water depth of 30 metres. The monopile for a 3.6 MW turbine: an outer diameter of 6500 mm; a wall thickness of 500 mm; and pile toe at -58 metre mean sea level (MSL) (1450 tonnes), while the monopile for a 5 MW turbine: an outer diameter of 6900 mm; a wall thickness of 700 mm; and pile toe at -61 metre MSL (2200 tonnes). The monopiles consist of pre-cast reinforced concrete ring elements. These will be assembled and post-tensioned to form a complete monopile. At the bottom of the monopile a steel pile toe is mounted to enable the monopile to ‘cut’ through the soil and create an overcut. Injection lines are cast in the concrete lining to fill the overcut with a self-hardening drill fluid. The work method consists of the following steps:

1. The monopile is self-floating and transported to vessel Svanen. The monopile is upended by Svanen;
2. The drilling machine is lowered into the monopile and hydraulically clamped;
3. Drilling starts inside the monopile and stops after settling. Drilling will continue underneath the monopile until the final depth is reached. During settling a self-hardening lubrication fluid will be injected in the overcut;
4. After completion of the drilling process the drilling machine is lifted out of the monopile.

The functional design for the drilling machine has been made. The cutter head is designed so that it is possible to drill through the various soil layers present at the Kriegers Flak site without exchanging the cutter head. The diameter of the cutter head is variable. This enables the machine to drill inside the monopole, as well as under the monopile lining. The cutter head is designed to excavate in two directions and is able to deal with boulders by crushing them in front of the cutter head.

A comparison of the application of a drilled concrete monopile with that of a traditional steel hammered monopile demonstrates that: the concrete drilled version will have a smaller impact on the environment; there will be no underwater noise or vibrations to cause damage to sealife; the carbon dioxide (CO2) emissions during fabrication of a concrete monopile are much lower than for a steel monopole; the durability of concrete in an offshore environment is much better than that of steel. There is no need for cathodic protection or coatings, which can emit metals such as aluminium or zinc.

In conclusion, the concrete monopile is a technically sound solution for an offshore wind turbine foundation, the installation of the concrete monopile by vertical micro-tunneling from HLV Svanen is a technically feasible concept, the drilled concrete monopile is economically competitive, especially for projects consisting of 40 or more foundations and the environmental impact is similar to or less than that of other types of foundations for offshore wind turbines.
DRILLED CONCRETE MONOPILE

Ballast Nedam Offshore and MT Piling have proposed a new offshore foundation concept. Ballast Nedam has significant experience in national and international infrastructure and offshore projects, and is the owner of heavy lifting vessel Svanen.

MT Piling is experienced in vertical microtunnelling. Between 2006 and 2007, the company constructed the vertical building pit walls of the North/South subway line under Amsterdam Central Station. The combination of the large heavy lifting vessel (HLV) Svanen and the vertical drilling technique resulted in the new offshore foundation concept called the Drilled Concrete Monopile.

There are key principles to the work method. A heavy concrete monopile is placed on the seabed by Svanen. This monopile will settle or sink by several metres under its own weight. When this settling stops, a drilling machine is lowered into the monopile. This machine will excavate soil from inside and under the monopile, resulting in the monopile settling again. This process of drilling and settling continues until the final depth is reached. Then the drilling machine is pulled out of the monopile. After placing the ice cone platform on top of the pile, the foundation is complete and the wind turbine can be placed. Finally the finishing works for the cable tube installation is carried out.

MONOPILE DESIGN

Concrete monopiles have been designed for 3.6 MW and 5 MW turbines in a water depth of 30 metres. The calculations are based on two representative soil profiles for the Kriegers Flak site: sand and clay.

The monopile foundations have an interface level at +3.5 metres MSL. The top of the monopile is fitted with a concrete ice cone. These are the results of the calculations:

Monopile for 3.6 MW turbine:
- Outer diameter 6500 mm; wall thickness 500 mm; pile toe at 58 metres MSL (1450 tonnes);
- Post-tensioning with 27 anchors, Cona BBR 22.06 (22 x 15.7 diameter wires);
- Reinforcement of about 85 kg/m³.

Monopile for 5 MW turbine:
- Outer diameter 6900 mm; wall thickness 700 mm; pile toe at 61 metres MSL (2200 tonnes);
- Post-tensioning with 37 anchors, Cona BBR 22.06 (22 x 15.7 diameter wires);
- Reinforcement of about 65 kg/m³.

All designed piles have an internal diameter of 5500 mm to fit the drilling machine.

CLICK TO VIEW FIGURE 2: MONOPILE DESIGN FOR 3.6 MW AND 5 MW TURBINES

MONOPILE FABRICATION

(I) PRODUCTION

The monopiles will be assembled from precast concrete ring elements which will be post-tensioned. The ring sections will be cast in the upright position. To increase the strength development of the concrete, the elements will be steam cured. After reaching sufficient strength the formwork will be released and the elements will be lifted to the storage area for at least two weeks of further curing.

CLICK TO VIEW FIGURE 3: ASSEMBLY OF MONOPILES FROM PRE-CAST CONCRETE ELEMENTS. PICTURES FROM THE BAHRAIN CAUSEWAY CONSTRUCTED BY BALLAST NEDAM

Each monopile will consist of a maximum of 12 elements. The element length is determined by the variation in the circumferential reinforcement distribution over the length of the pile. A maximum element length of six metres is chosen for the practical reasons of concrete pouring. The maximum element weight to be lifted by the gantry crane will be 200 tonnes.

After reaching a sufficient strength the concrete ring elements will be lifted to the pile assembly line. The elements will be aligned with an offset of several centimetres.

The cable duct pipes are then interconnected and sealed. The joint between the elements will be made by grouting, which guarantees a full contact surface, and therefore prevents cracking of the concrete during post-tensioning.

The posttensioning cables will be installed in the cable duct pipes. The monopile will be posttensioned from both sides in several stages until 100 per cent post-tensioning is reached.

The assembled monopile is transported to the storage area for further finishing works. The monopiles are too heavy to be lifted. Horizontal transport could consist of transport lines with hydraulic jack vehicles. The following activities will be performed in the finishing works production line:

- Grouting of the cable duct pipes;
- Installation of pile toe;
- Installation of injection lines for lubricating and hardening fluid;
- Installation of pile plugs in both ends of the pile for floating transport.

After completion of these finishing works the monopile is ready for load-out.
II) PILE TOE
A steel ring is constructed at the toe of the concrete pile. This enables the monopile to ‘cut’ through the soil and settle. The shape of the toe forces the soil underneath the toe and inside the monopile during settlement.

The height of the steel ring is 1 metre, which is two times the monopile wall thickness. The monopile’s diameter is extended at the pile toe to create a larger borehole than the pile diameter. The width of this annular space is 10 cm.

The annular space will be filled with lubricating and hardening fluid. For this, different injection pipes are constructed in the concrete lining of the monopile. These lines end in injection points scattered around the outside of the monopile mantle.

**STEEL PILE TOE**

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**MONOPILE INSTALLATION**

II) WORK METHOD
The following steps explains the work method for installing the concrete monopiles and ice cones:

**STEP 1: DELIVERY OF ICE CONE PLATFORM**
The HLV Svanen is anchored in position. A pontoon which holds two ice cone platforms will be brought in between the floaters of Svanen. One ice cone platform will be lifted with the rear main hook on the port side.

**CLICK HERE TO VIEW FIGURE 5:**
**STEP 1: ICE CONE PLATFORM LIFTED FROM PONTOON**

When the first ice cone platform has been lifted the pontoon will be demobilized from the Svanen and temporarily parked near the offshore site until the installation works for the next foundation begins.

**STEP 2: DELIVERY OF THE MONOPILE – UPENDING THE MONOPILE**
The self floating monopile is transported to the Svanen and brought in between the floaters of the vessel. Specially designed seals at both sides of the monopile prevent water from flowing into the monopile.

The monopile will be slowly lowered, guided by the frame, and will settle into the seabed at a depth of some metres. During the lowering the verticality will be monitored and, if needed, corrected by the constant tensioning anchor system of Svanen. Before lowering, a seabed scan is made for obstacles.

The monopile is released from the main hoist and kept in position by the guiding frame. No large heave compensator is required because the monopile is placed on the seabed and released from the hook.

**POLYPITE TO VIEW FIGURE 7:**
**STEP 3: MONOPILE POSITIONED IN GUIDING FRAME**
**STEP 3: MONOPILE PITCHED ON SEABED**

**STEP 4: LOWERING THE DRILLING MACHINE INTO THE MONOPILE**
Svanen is moved into position for lowering the drilling machine into the monopile. During the movement of the Svanen, the fixing of the monopile is controlled continuously by the guiding frame. The guiding frame with the monopile moves over the hull of the Svanen at the same speed but in the opposite direction to the movement of the Svanen. The position of the monopile on the seabed remains unchanged.

The hoisting frame with the drilling machine is carefully lifted above the monopile. From the hoisting frame the drilling machine, cables and hoses are lowered into the monopile.

The lubrication fluid system is connected to the injection lines to inject the fluid in the overcut of the monopile.

**CLICK HERE TO VIEW FIGURE 8:**
**STEP 4: DRILLING MACHINE ALIGNED OVER THE MONOPILE**
**STEP 4: DRILLING MACHINE LOWERED INTO THE MONOPILE**

**STEP 5: DRILLING INSIDE THE MONOPILE**
The drilling machine is lowered into the monopile and installed at the correct height on top of soil inside the monopile. The clamping frame fixes the drill inside the monopile by pushing out horizontal jacks.

The drilling machine is pushed down by the vertical jacks of the clamping frame. While pushed down, the drilling machine excavates soil from the inside of the monopile and drills with an internal diameter of 5300 mm.

By monitoring the hydraulic pressure in the vertical jacks, the force of the cutter head on the excavation front is regulated. Altering this force alters the force on the cutter head. This regulates the excavation speed, so the force in the vertical jacks determines the excavation speed.
The objective is to settle with constant speed and to let the drilling machine settle simultaneously with the monopile. Different soil layers have different resistances, so it is possible that the monopile may settle more quickly or more slowly than the drilling machine. This process is regulated by extending and retracting the vertical jacks with constant force, which maintains a constant force on the cutter head. This force is monitored and controlled exactly. The settlement process will continue until resistance is larger than the monopile’s effective weight, as will be the case in hard soil, hard layers of flint, or boulders, for example.

**STEP 6: ICE CONE PLATFORM ALIGNED ABOVE THE MONOPILE**

Click here to view Figure 10:

### STEP 6: INSTALLATION AND GROUTING OF THE ICE CONE PLATFORM

In Figure 5 the position of the drilling machine is shown in the deeper soil layers. In the harder clay till and limestone layers in particular, the drilling machine has to excavate resistance could become too large for the monopile to settle with this drilling process. This is when drilling under the monopile begins. The cutter head is gradually extended towards the outer diameter of the monopile. It excavates under the monopile but always inside the steel pile toe. The drilling machine is pushed down by the vertical jacks of the clamping frame. Again the jacking force from the vertical jacks determines the excavation speed. The settlement of the monopile is a result of this excavation speed. The drilling under the monopile continues until final depth is reached.

### INSTALLATION EQUIPMENT

#### (I) DRILLING MACHINE

**A. INTRODUCTION**

We now describe the functions of the drilling machine, a first design of which has been made:

- The drilling machine should be able to drill through all soil types present at the Kriegers Flak project. This requires the design of a custom cutter head;
- The drilling machine is fixed inside the monopile and can be moved vertically. To start drilling the machine is pushed forward and the monopile settles. The force on the cutter head is controllable. The clamping frame in combination with the vertical jacks provides these functions;
- The excavated soil is removed from the cutter head into the slurry system by the discharge pump;
- The drilling machine is able to deal with the cobbles and boulders that are present in the soil layers;

The picture on the left in Figure 5 shows the position of the drilling machine at the start of the drilling process. The drilling machine is excavating soil from the inside of the monopile, with the smaller cutter head diameter of 5300 mm. The picture on the right in Figure 5 shows the position of the drilling machine in the deeper soil layers. In the harder clay till and limestone layers in particular, the drilling machine has to excavate soil under the monopile lining to make sure the pile will settle. Therefore the cutter head can be extended to 7100 mm.

**CLICK HERE TO VIEW FIGURE 11:**

#### B. CUTTER HEAD

The diameter of the cutter head varies hydraulically. It is:

- 5300 mm for drilling inside monopile, with 10 cm of space between the drilling machine and the inside of the monopile;
- 6700 mm and 7100 mm for the 3.6 MW and 5 MW monopiles respectively, for drilling under the monopile with the external pile diameter and an extra 10 cm for the overcut.

Click here to view Figure 9:

### STEP 5: DRILLING INSIDE THE MONOPILE

Drilling inside the monopile continues until the pile toe level is reached. At a certain depth – calculated at 10–15 metres – the soil resistance could become too large for the monopile to settle with this drilling process. The picture on the right in Figure 5 shows the position of the drilling machine operating inside (left) and under (right) the monopile.

When the final depth is reached, the cutter head ‘teeth’ are retracted and the cutter head is again at its smallest diameter. A design of a custom cutter head;

- The drilling machine should be able to drill through all soil types present at the Kriegers Flak project. This requires the design of a custom cutter head;
- The drilling machine is fixed inside the monopile and can be moved vertically. To start drilling the machine is pushed forward and the monopile settles. The force on the cutter head is controllable. The clamping frame in combination with the vertical jacks provides these functions;
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To provide the variation in diameter, the outer part of the cutter head – the so-called teeth – can be pushed out hydraulically. The teeth will only be pushed out inside the steel ring under the
monopile. In an emergency the drilling machine can be pulled up and the teeth are forced back into the cutter head by the steel ring. Water jets are placed on the outer part of the cutter head to make sure the soil under the monopile lining disintegrate. In this way the soil here can be excavated by jetting, even without having to extend the diameter of the cutter heads.

The cutter head is designed to drill through various soil types. A single cutter head is used for all types of soil rather than exchanging cutter heads to suit the soil.

The cutter head excavates in two directions. This prevents blockage of the cutting head and compensates for the rotation of the monopile, which is caused by the reaction of the driving torque of the cutting head. In this way the exact final orientation of the monopile is ensured.

C. CLAMPING FRAME

The clamping frame is integrated in the drilling machine and is the construction which fixes the drilling machine inside the monopile. The torque from the cutter head is transferred via the clamping frame to the monopile. The horizontal jacks of the clamping frame create a load on the inside of the monopile.

This load should not exceed the capacity of the concrete lining. To ensure this is the case, the load should be equally distributed over a height of at least 1 metre.

E. DRILLING PARAMETERS

Jacking force: The total weight of the drilling machine, including the cutter head, clamping frame, bearing and pumps is 1500-3000 kN. By extending the vertical jacks, extra weight from the monopile can be mobilized for jacking force. This is about two times the weight of the monopile.

Torque: The required torque is estimated at 6000 kNm. This figure comes from experience with large-diameter TBMs and the MT Piling vertical drilling machine used at the Amsterdam Central Station. The resulting weight of the monopile under water provides a continuous load on the soil during the drilling process. This results in a continuous frictional force that is large enough to counteract the reaction force – the torque – of the drilling machine.

As an extra measure to address the torque, guiding wheels are placed on the guiding frame on Svanen.
Drilling speed: The estimated average drilling speed — the settlement speed of the monopile — is 50 mm/minute. The slurry circuit design allows a maximum drilling speed of 100 mm/minute.

Rotational speed: The rotational speed depends on the type of soil under excavation but will be in the range 2-5 rev/minute.

III. OVERCUT/ANNULAR SPACE

The option to drill the monopile without the creation of an annular space or with a very small annular space has been reviewed. No drilling fluid would be used, just lubrication fluid. However, the horizontal soil relaxation is expected to be between 30-85 mm. When no overcut is created this relaxation creates a large horizontal pressure on the monopile.

Even with a small calculated wall friction coefficient between monopile and soil, the soil pressure will be too large. The risk of the monopile being fixed by the soil, resulting in little to no settlement of the pile, is too large.

To prevent this and to minimize wall friction during drilling an annular space is created. The annular space should be larger than the expected soil relaxation. A first estimate for this is a width of 100 mm.

A material called drill mix is chosen to fill the annular space. Because of its lubrication and the relatively large annular space, very little wall friction remains around the monopile. The fluid prevents soil relaxation due to its density of about 1200 kg/m³, which is higher than that of water.

After drilling, the fluid will harden to a strength of about 3.5 N/mm². A minimal compression strength of 2.1 N/mm² is required.

ECONOMY

A cost estimate has been made based on fabrication and installation in a continuous process of up to 150 foundations. This results in:

- Investment in two drilling machines, for maintenance and back-up
- A large prefab yard of area about 48,000 m²

The following assumptions have been made:

- The foundations are for water depth of 30 metres;
- The prefab yard is in the harbour of Sassnitz, Germany;
- Investment in the prefab yard for a production capacity of one pile every 2 day. This totals 365 days, including startup time;
- Installation with HIV Svanen (net cycle 48 hours, 256 days);
- Production and installation of the total project (128 units) in a continuous process;
- Excavated soil may be dumped close to the foundation;
- This excludes unworkable weather.

The cost of the foundations will fall to:

- About €500 000 ($643 000)/MW for 3.6 MW turbines;
- About €400 000 ($514 000)/MW for 5 MW turbines

ENVIRONMENTAL ASPECTS

The big advantages of drilling a concrete monopile instead of hammering a steel piling are:

- There is no underwater noise;
- There are no vibrations;
- There are no emissions of heavy metals because no cathodic protection is required.

With hammering, underwater noise and vibrations cannot be eliminated. This can have a very large impact on the environment, for example on sea mammals.

CONCLUSIONS

This paper has described the design, fabrication and installation of drilled concrete monopiles.

Different designs have been made for different wind turbines, water depths and soil conditions. The monopiles are assemblies of concrete ring elements that are post-tensioned. The production can take place at a yard in a nearby harbour.

Because the monopiles are concrete their production does not depend on the three main suppliers of steel. Besides that the costs involved depend less on the fluctuations of market prices or on availability.

This paper has described the installation method in detail. External parties have been consulted to overcome the initial challenges in the drilling process.

Thus in conclusion: the concrete monopile is a technically sound solution for the foundations for offshore wind turbines; the installation of the concrete monopile by vertical microtunnelling from HIV Svanen is a technically feasible concept; the drilled concrete monopile is economically very competitive, especially for projects consisting of 40 or more foundations; and the environmental impact is smaller than for other types of offshore wind turbine foundation.
Benefit of a Prediction System for Integrating Electrical Vehicles into Electrical Grids

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ABSTRACT
In times of increasing power feed-in from fluctuating renewable energy sources the demand for storage capacity to compensate such fluctuations rises. Electric vehicles in ever increasing numbers could form an effective means for storage. To take advantage of these conditions it is important to assess the current and future available overall storage capacity. This paper analyzes the future demand of available storage capacity in electrical vehicles as a method of supporting higher integration of fluctuating power sources.

To support the use of this storage concept in electrical grids we propose a system that will predict storage capacity and power consumption during the charging of electrical vehicles, as well as incorporate forecasts for wind power and photovoltaic feed-in. Such a prediction system can help to integrate electrical vehicles into a grid. Together with renewable energy feed-in forecasts, it provides solutions that will deal with fluctuating renewable energy sources that have a high grid penetration.

1. INTRODUCTION
The facts behind climate change are evident. The increasing use of clean and abundant renewable energy (RE) provides a path out of the fossil-fuel dilemma. However, increasing power feed-in from these fluctuating resources poses a serious challenge for established electricity networks. Besides the massive deployment of information and communications technology (ICT) to smarten the grid, one solution that compensates for such fluctuations is an adequate energy storage capacity. There are several storage options, for example hydro pumped storage, heat storage, compressed air storage – eventually – or even renewable power methane [1]. Furthermore, electric vehicles (EVs) in suitably large numbers could provide additional storage and a controllable load if demand-side management is used.

The German government has an ambitious national plan for deploying EVs [2]. This plan takes into account a fleet size of one million EVs by 2020 and five million by 2030. Further studies [3] support the trend for a fast growing market for EVs.

Several small and medium-sized enterprises are engaging in the production or distribution of EVs while the big automotive companies seem still to be standing by or waiting for a large-scale development.

Doubts that have arisen that the additional power load requirements for the charging of EVs would require the installation of new power plants, possibly running on fossil fuels, have been rejected, for example by the German Wind Energy Association [4]. That organization’s plan is to produce sustainable energy solely from wind, which would amount to around 1.50 TWh in 2020. By comparing this figure for RE inputs with the parallel load needed for charging 1-2 million EVs of approximately 2 TWh, it is apparent that these EVs would be powered by RE.

Research [5–7] has already shown how the controlled charging and discharging of EVs can support the integration of fluctuating RE into an electrical grid. Although the assumptions of this research are always that future generation by RE and the future load for charging of EVs are both already known.

It has also been shown [7] that EVs can principally mitigate fluctuations. However, it has not yet been demonstrated whether the implementation of such a feature into a system really would be possible.

In this paper we will show that the use of suitable prediction systems makes the controlled charging of EVs possible and that this supports the grid integration of RE. We first develop a model that simulates the behaviour of a mass of EVs from the grid side, and then use the model to build a system to predict the storage and load of EVs. Next we introduce an information model that describes the processing of the data (RE, EV load and storage, and grid load) to manage the EV load to compensate for fluctuating RE feed-in. We then present an implementation of this information model for charging EVs on the basis of prediction systems. It uses the load and storage prediction system, as well as the RE prediction system developed by
Fraunhofer IWES [8]. We subsequently describe the potential for load-shifting and for using the EV storage to compensate for RE feed-in fluctuations, concluding with a summary of our results.

2. SIMULATION MODEL
The number of total vehicles in Germany is 40 million [10]. In January 2009, there were about 1400 EVs registered [9], a small number in comparison to too small to allow analysis of the behaviour of EVs with respect to their spatial distribution. Furthermore, available detailed data about these EVs are insufficient. As a consequence, a model was built that simulates the behaviour of a large number of EVs in a given geographical area. The results of this simulation were used to develop a model for load and storage predictions for EVs.

It is important to note that the predictions depend highly on the selected simulation model. So all statements about the quality of the prediction model are only valid with reference to our simulation model and cannot be translated into reality.

The simulation model is based on data from the MiD 2002 survey on the mobility behaviour of households in Germany [11]. This study comprises interview answers from individuals in 25,000 households across Germany. They were asked about their mobility behaviour for a selected day of the week. From this data set all single trips were selected which were conducted by car, amounting to 5,700 trips. These trips were then clustered accordingly by the day of the week. We used an agent-based simulation model where the EVs and their drivers act as agents. This allowed us to generate fine-grained behavioural information about these vehicles. For our simulation model the individual trips by people in the households were analyzed. We considered the start times, driving durations and driving distances of trips that were under 150 km.

We did not consider trips above 150 km because we assumed that in the near future EVs will typically be used for short trips. With the use of these data, statistical distributions of start-times, driving durations and driving distances were calculated. These distributions are used by the simulation to determine whether an agent starts its trip during a given hour or not and for how many simulation steps (duration) the agent is driving. Furthermore, the energy consumption for each agent was calculated by determining the driving distance according to the distance distribution.

The input data from MiD 2002 was divided into two distinct groups: business and private uses of the EV. To keep the model simple according to the distance distribution. For each agent was calculated by determining the driving distance (duration) the agent is driving. Furthermore, system were also not considered. This simplification leads to an energy-consuming units such as air conditioners or auxiliary heating systems were not considered. This simplification leads to an energy consumption of the EV that is independent of weather and available technology.

The behaviour of the car drivers is modelled in a very straightforward way. A calculation is made after each trip of how much energy will be needed for the next trip. If the state of charge (SOC) of the vehicle is insufficient to cover the next trip, the driver has to plug-in the vehicle. Otherwise the driver may charge the vehicle's battery with an assumed probability of 0.1. The value 0.1 was determined by a sensitivity analysis. The vehicle is charged either until the maximum SOC is reached or the vehicle is unplugged.

2.1 SIMULATION RESULTS
We ran the model for the reference year 2008 with the actual electric load and RE feed-in data. This gave us a typical driving curve that shows the number of cars driving at a specific time during one week (see Figure 1).

CLICK TO VIEW FIGURE 1:
SIMULATED RELATIVE NUMBER OF EV (SOLID), EV LOAD (DASHED) AND THE SOC OF ALL TO THE GRID-CONNECTED EV (DOTTED) OVER ONE WEEK.
The results of the simulation indicate that at a peak time there were approximately 700 drivers (7 per cent) en route at the same time. The shape of the driving progression is comparable to the transportation demands found in [6] and [7, 12], which are based on the same data but make use of a different models.

We calculated the average annual driving distance (AADD) of one vehicle in order to evaluate whether the number of vehicles driving during one quarter hour, which was the simulation step width, is plausible. The simulated AADD resulted in around 8000 km per vehicle, which is smaller than the real AADD in Germany, which is 14 000 km [18].

The difference emerges because only trips with a maximum length of 150 km were considered in the simulation model. In reality, the number of trips also includes long-range drives that add up to produce the higher total annual sum. This deviation is also persistent when analyzing the original statistical data input to our model.

To evaluate whether the simulation findings can be transferred from Germany to the region of Harz, we compared the driving behaviour during a week of the simulation with that of an actual traffic count [19] in this region. The simulation is based on the assumption that 8 per cent of all vehicles are EVs.

Absolute vehicle numbers resulting from a local traffic count and from region-wide simulation cannot be directly compared. So only figures which are relative to the overall number of moved cars are evaluated. The results of the comparison are shown in Figure 2. The curve progressions are comparable and therefore the simulation results can be used for an evaluation of the region of Harz. The correlation of both curves is 0.95, which indicates that the simulation assumptions can be treated as realistic for this region of Germany.

3. EVS LOAD AND STORAGE PREDICTION

The EV simulation provides the data necessary to build a prediction system for EV load and storage. For both predictions, a model was developed which is based on a method called ‘nearest-neighbour search’. These predictions are then evaluated by using EV simulation results to determine their degree of precision.

3.1 NEAREST-NEIGHBOUR SEARCH

The nearest-neighbour search is a heuristic approach. The prediction is based on the assumption that a value pair of input and output parameters in the future can exactly or approximately be found among the data pairs from the past. The actual algorithm searches all input values of the past to find the one that is the closest to the given input value. For quantifying this similarity between the given input and the past input the Euclidian distance is often used [20].

The EV load and storage prediction are modelled as followed:

**EV load prediction:**
- **Input:**
  - a. Day of week (DoW)
  - b. Time of day (ToD)
- **Output:** EV load ($P_{l,DoW,ToD}$)

**EV SOC prediction:**
- **Input:**
  - a. Day of week (DoW)
  - b. Time of day (ToD)
- **Output:** EV SOC ($S_{l,DoW,ToD}$)

Because of the nature of input parameters DoW and ToD it is not necessary here to calculate the distance to the past input data. A more efficient way is to search the suitable input values DoW and ToD in the past input data. The corresponding EV load or SOC values are then selected and used to represent the prediction values.
3.2 Prediction Results
The developed prediction models for EV load and SOC are applied to the simulation previously mentioned. The predictions were developed by using 70 per cent of the weeks in simulated year 2008. The remaining 30 per cent are used to evaluate their performance. An example week is shown in Figure 3. In the upper graph, the EV load prediction and the load simulation results are compared. In the lower graph, the SOC simulation and prediction results are displayed.

CLICK TO VIEW FIGURE 3:
MEASURED AND PREDICTED EV LOAD (TOP) AND EV SOC (BOTTOM)

Both predictions clearly feature the same characteristics as their simulations. In the case of the EV SOC, the differences between simulation and prediction are somewhat bigger when compared with those in the case of the EV load. To quantify the performance of the EV load and SOC predictions the following criteria are used:

- Root Mean Square Error (RMSE) and Normalized Root Mean Square Error (NRMSE):

\[
RMSE = \sqrt{\frac{1}{N} \sum_{i=1}^{N} (x_{\text{pred},i} - x_{\text{meas},i})^2} \quad \text{NRMSE} = \frac{\text{RMSE}}{x_{\text{min},i}}
\]

- Bias:

\[
\text{Bias} = \frac{1}{N} \sum_{i=1}^{N} (x_{\text{pred},i} - x_{\text{meas},i})
\]

- Correlation:

Because it can be derived from the results that have come from all performance criteria both prediction models accommodate their problems well. The error distributions in Figure 4 also show good characteristics. The error bandwidth is small and most errors are near zero.

CLICK TO VIEW FIGURE 4:
ERLOR DISTRIBUTIONS FOR THE EV LOAD (TOP) AND EV SOC (BOTTOM)

These results represent the performance of predictions from a simulation model applied to the same simulation model. Therefore it is necessary to develop an advanced prediction model for real-life situations. For example, seasonal influences such as temperature fluctuations have to be included.

4. Information Model for EV Load Management
Shifting the EV load to times with higher RE feed-in or using their storage capacity to compensate for the fluctuating feed is topics that are discussed [5, 6, 8]. For both techniques, referred to as smart loading – in contrast to dumb loading – or V2G, it has been shown that they can support the integration of more RE into the grid. But none of the concepts or systems that have been discussed can be used to manage the load of EVs in real time. The common assumptions in all of these concepts or systems are that the energy feed-in and future load are known. This is not always true for RE feed-in and load. To manage EV charging at run-time it is useful to possess future feed-in and electrical load information. To get such information, sophisticated prediction systems are recommended.

To support the integration of RE into the grid, the fluctuating feed-in situation has to be compensated for. From the grid side, this can be achieved by load management of EVs that allows the shifting of EV charging to times with high RE feed-in and using the EVs as a generation unit by discharging the EV battery. Reference [21] introduced a framework for EV load management and the presented ‘aggregator’ as its main concept. This aggregator manages all EVs into a combined load and allows the energy service provider and the independent system operator or regional transmission organization to control the charging process. Furthermore, a model was presented that computes the input data that can be used to control the loading of a single EV by such an aggregator.

This paper proposes an information model that describes the processing of the prognosis data (RE, EV load and storage, and grid load) to manage the EV load in order to compensate fluctuating RE feed-in. The prognosis data are provided by the following prediction systems: a prediction system that forecasts the RE feed-in – we used a system based on the Fraunhofer IWES Wind Power Management System (WPMS) [8] that considers the feed-in of wind, photovoltaic, biogas, and hydropower, a prediction system for the grid load, and the presented prediction system for the EV load and storage.

As a basis for decision-making on whether the EV should charge or not, we chose as a measure the ‘residual load’. This is the electric load minus the RE feed-in, as defined in [7]. It is an indicator of the share of RE of the common feed-in, or overall generation. Its value is positive when more load than RE feed-in exists and negative when the RE feed-in surpasses the load.

When both the RE feed-in and load are in balance, the residual load is zero. The residual load is considered because the fluctuating nature of the RE feed-in would not be a problem when the load fluctuates in the same way. Therefore, the smoothing of the residual load curve best supports the integration of RE into the grid.
For our model, the RE prediction and the grid load prediction are combined to create a common prediction for the residual load (see Figure 5). This calculated residual load is then used as the first input for the load management and has the greatest influence on decision-making.

**CLICK HERE TO VIEW FIGURE 5: INFORMATION MODEL FOR EV LOAD MANAGEMENT**

The second input for the load management model consists of the prediction of EV load and storage. This load is not taken as part of the conventional grid load prediction to keep the manageable and non-manageable loads separate. We only consider the EVs as manageable load.

With the information from the EV load prediction the load management provides an estimate of the future EV load. It is important to note that the applied load management then renders the results of the EV load prediction incorrect because the prediction model run was originally based on the assumption that no load management existed.

Nevertheless, the information from the EV load prediction is very useful because the load management determines how much energy the EVs will consume in a period of time in the future. It can then estimate by how much time this charging should be shifted.

Regarding the scenario in which the EVs are not controlled by a load management system, our prediction can be used to estimate the load of the EVs. In combination with the conventional grid load prediction these predictions are typically used by distribution system operators (DSOs) or transmission system operator (TSOs) to estimate operational behaviour of the future system state.

When load control is applied as in the proposed information model the outcome of the load management system replaces the previous results of the load prediction. Thus the load management determines the new load curve and therefore in this model takes over the role of load prediction.

The prediction of the storage of EVs may be used to manage generation in V2G concepts. The combined storage capacity of all EVs connected to the grid indicates how much energy can be used to support the grid by discharging EVs’ batteries. This holds even if some of the storage cannot be used because of the minimum reserve requirements for the following EV trips. The fraction of the storage that can be used to support the grid has to be estimated.

Like the prediction for EV load, the EV storage prediction is based on the assumption that there is no load management. However, if the prediction is used as an indicator for load management the information can be useful.

This is because shifting the whole load means shifting the SOC curve of all EVs together. Therefore the SOC curve with load management can be calculated by the ‘old’ SOC curve and the load shift plan. It is important to note that all our analyses and propositions are made under the basic assumption that the charging process of a specific EV cannot be shifted ahead to any length. The model always considers that each EV – or, more precisely, each individual driver – that is connected to the grid is going to be on route at a specific time in the future. So until this point in time the required SOC must be reached to permit driving of the designated trip.

**5. MODEL IMPLEMENTATION**

The information model we have described to manage the EV load – based on predictions for EV load, EV SOC and residual load – is now applied to the results of our simulation. Data from a randomly chosen week – 3 March 2008 to 10 March 2008 – is used. Both the models for EV load and for feed-in management will be realized independently. At first an implementation for pure load management is discussed, followed by an implementation for managing feed-in with subsequent recharging.

To evaluate the possible time-shift it is assumed that at least 75 per cent of all charging processes last longer than the maximum used time-shift. In our simulation model, this relates to five hours during weekdays, six hours on Saturdays and seven hours on Sundays.

For load management an optimization is used, which calculates a load schedule for EVs by shifting the predicted EV load to times where residual load is lowest in the considered time interval, for example current time plus 5 hours during weekdays.

In Figure 6, the results of the EV load management and their application to the real residual load are shown. It is clear that EV load management shifts the EV load, if possible, to valleys in the residual load prediction. The standard deviation (STD) in Table 2 indicates that the variability of the predicted residual load decreases slightly when applying managed EV load. On the contrary, the unmanaged EV load increase the variability in the curve shape.

**CLICK HERE TO VIEW FIGURE 6: EV LOAD PREDICTION OPTIMIZED TO RESIDUAL LOAD PREDICTION [TOP] AND THE RESULTING REAL RESIDENTIAL LOAD [BOTTOM]**

**CLICK HERE TO VIEW TABLE 2: STANDARD DEVIATION FOR THE REAL AND PREDICTED RESIDUAL LOAD WITH THE PREDICTED EV LOAD**

Thus, EV load management induces a smoothing effect. Furthermore the managed EV load applied to the real residual load generates a different result. Because of errors in the residual load prediction the managed EV load is not exclusively shifted to the valleys of the real residual load. The predicted valleys do not always occur in real life. As a consequence there is no smoothing effect.
of the residual load observable, as the STD in Table 2 indicates. However, the EV load management does reduce the impact of the EV load.

For the EV feed-in management (V2G) the same data basis is used as for the EV load management (see above). Optimization is also used to shift the EV feed-in from EV storage to points in time where predicted residual load is highest. The usable feed-in fraction, or feed-in without reload for the next trip, of the grid connected SOC never falls below 60 per cent in our simulation.

We use this fraction of the EV SOC prediction for feed-in management. As time interval in which the whole energy as feed-in is used are 24 hours applied. The same amount of energy has to be recharged in these 24 hours. Today this is not a very cost effective approach. Nevertheless it shows the technical potential of EV feed-in management.

The effect of this management is a smoothing of the residual load, which is displayed in Figure 7. As seen with the EV load management the feed-in management exhibits the same differences between the predicted and the real residual load. Contrary to the EV load management a certain degree of smoothing is also achieved within the real residual load. This is seen in the decrease in STD of almost 1.1 MW.

The integration of 10,000 EVs in the region of Harz is easily achievable. Using EV load and feed-in management to control the EVs connected to the grid reduces the impact of a high number of EVs on grid operation. Combining the EV load and feed-in management may even result in conditions that could support a higher share of fluctuating RE in the grid. The EV charging then goes in parallel with high-current RE feed-in, and discharging in parallel with low RE feed-in.

6. SUMMARY

We have demonstrated how the prediction of RE, EV load and storage can contribute to the integration of RE onto the grid. This can be achieved by employing the EVs’ storage capacity. A simulation model was set up and successfully validated by using several sources. The results of the simulation were used to develop an EV load and storage prediction.

This prediction approach can be easily adjusted further to real-life by expanding the input parameters, for example, by including temperature. Furthermore, we presented information that incorporates multiple prediction systems such as EV storage or RE prediction. It was successfully applied to a load management system for charging EVs. We presented the results of a possible implementation of this model.

On the one hand, it was shown that by using pure load management – which only considers load shifting – the impact of EVs on the real residual load could be reduced. On the other hand, pure feed-in management – where EVs act as flexible storage – smoothed the residual load curve shape.

In addition to previously published articles we explicitly considered the effects of prediction errors. Indeed we showed that this procedure leads to more realistic results but at the same time reduces the positive effect of EVs on the grid in a controlled charging scenario.

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Bio-oil Production Intergrated with a Fluidized Bed Boiler - Experiences from a Pilot Project

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ABSTRACT
A fast pyrolysis unit can be integrated with a fluidized bed boiler. Based on such a concept, the pyrolysis unit utilizes the hot sand in the fluidized bed boiler as a heat source. The devolatilized gas compounds are condensed into bio-oil and the remaining solids, including sand and fuel char, returned to the fluidized bed boiler. In the boiler, the remaining fuel char is combusted to produce heat and electricity. Metsä has built a 7 tonnes/day integrated bio-oil pilot plant utilizing saw dust and forest residues as feedstock, in cooperation with UPM and the Technical Research Center of Finland. As part of the project, a novel integrated wood based bio-oil concept will be developed. The related concept covers the entire business chain, from feedstock purchase and pre-treatment to bio-oil production, transportation, storage and end use. In this paper, the pilot project will be described in more detail and the experiences gained from the piloting and bio-oil combustion tests will be presented. Also, the potential of integrated bio-oil production and the required utilization chain will be discussed.

1. INTRODUCTION
Bio-oils from plant residues are alternatives to fossil fuels and feedstocks. The use of bio-oil in industrial kilns, boilers, diesel engines and gas turbines has been tested. The use in the production of chemicals and feedstock for the production of synthesis gas and the further production of transportation fuels and C1 chemicals is also being developed. Bio-oil has also been upgraded, on a small-scale, to transportation fuel fractions. However, today bio-oil is only used commercially in the food flavouring industry [1].

Bio-oil, frequently also referred to as bio crude, fast pyrolysis oil or pyrolysis liquid, is a potential source of revenue for companies that have biomass residues at their disposal, for example forest residues, forest industry residues and some agricultural residues such as straw. It has been estimated that these residues offer a considerable, potential source for conversion. However, many residues such as straw are difficult to accumulate in large quantities in a single location at a competitive cost.

Bio-oils can be shipped, stored and used much like conventional liquid fuels if their specific fuel properties are taken into account. As test use over the years has shown, the quality of bio-oil varies considerably. However, once large-scale observations are available, the specific properties of bio-oils will be better understood and proper procedures for use developed.

Introducing a new fuel such as bio-oil to market will not be easy. Bio-oil is somewhat different to conventional liquid fuels and many challenges remain. Difficulties like this means a stepwise market introduction is proposed. Bio-oil would first replace fuel oil in boilers, where its properties would not prove prohibitive. An example of such a chain has been presented earlier [2]. Once the entire chain from biomass to fast pyrolysis plants to heat use has been proven, other applications may be demonstrated.

There is general awareness of the competition for good quality biomasses for use as fuel. Biomass is especially popular in power production. Market incentives are in place in many European Union (EU) countries for the production of green electricity. Power plants will remain large users of wood fuels because, for example, modern fluidized bed boilers can use several types of biomass. To compete in the market, bio-oil production must provide a higher payoff for the investor than the current alternatives.

The bio-oil production potential of the European pulp and paper industry has been analyzed by Sipilä et al [3]. Their findings show that the European pulp and paper industry has the potential to build up to 50 pyrolyzers integrated in fluidized bed boilers. In the short-term, the bio-oil market lies...
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Jani Lehto
Metso Power

was selected by the Best Paper Awards Committee as one of the three finalists for the conference paper entitled

Bio-oil production integrated to a fluidized bed boiler: experiences from a pilot project
in fuel oil and natural gas replacement in lime kilns and boilers. The challenge is to develop and demonstrate a technical and economic concept for these applications.

2. INTEGRATED BIO-OIL PRODUCTION CONCEPT
The Finnish have a long and successful history of developing fluidized bed technology. Over time Metso has delivered hundreds of fluidized bed boilers for the commercial production of electricity and heat for the pulp and paper industry and power generating companies worldwide. As environmentally friendly energy technologies are becoming more popular, as a technology company, Metso must be able to develop more versatile solutions to meet customers’ needs. During the last few years the focus has shifted towards energy efficiency, replacing fossil fuels and increasing the value gained from biomass.

The hot sand of a fluidized bed boiler offers considerable potential for the integration in that system of the pyrolysis and combustion processes. A fluidized bed boiler acts as a heat source for pyrolysis, in addition to which it can easily combust the coke and uncondensed gases produced during the pyrolysis process to produce electricity and heat. In this way high efficiency can be achieved for pyrolyzed fuel.

In addition, when integrated with a fluidized bed boiler, pyrolysis is a cost-efficient way of producing bio-oil, which can be used to replace fossil oils. Considerable savings can be achieved in operating costs and the price of the investment in both new boiler projects and retrofit solutions.

Industrial fluidized bed boilers are very large in size. At their largest they output hundreds of MW, so even large pyrolyzers can be integrated. The operation of the entire integrated plant can be optimized through efficient and intelligent automation.

3. JOINT VENTURE
Metso, UPM and Fortum have agreed on a joint venture that forms part of a more extensive development programme that focuses on the development of pyrolysis technology and its introduction to the market. This joint venture, which targets the promotion and advancement of research on an integrated bio-oil concept, involves expertise in the implementation of this concept across the entire value and production chain.

Metso is in charge of delivering the related technology. UPM, a raw material supplier, plant operator and user of the final product, and Fortum, a plant operator and user of the final product, complete the value chain. Finland’s technical research centre VTT is a research partner in the work. The joint venture aims to develop a new bio-oil concept according to which liquid bio-oil will be produced by a pyrolyzer integrated in a fluidized bed power boiler. Concept development covers the entire production and use chain, from raw material acquisition and pretreatment to bio-oil logistics and use in Finnish and global markets. Production technology development and the creation of the required business operations began in the first phase of the joint venture.

The cooperating companies will have significant opportunities to use pyrolysis technology if the development work succeeds from the point of view of both technical and economic competitiveness.

UPM is among the most important users of wood-based raw materials in Finland. It has taken the strategic decision to invest in second generation biofuel concepts. This bio-oil concept, based on fast integrated pyrolysis technology, agrees with such a strategy.

Bio-oil production will be integrated with an existing fluidized bed boiler operating at the mill site, reducing the operating and investment costs of the concept. Feedstocks for the bio-oil are forest residues and sawdust, the byproducts of UPMs current business. While the moisture content of these feedstocks is typically high, the fast pyrolysis process requires dry feed. At the mill site, excess waste heat can be used to dry the pyrolysis feed.

The company plans to exploit the potential of several commercial pyrolysis plants in terms of bio-oil production, for its own use as well as for sale to the market, through current and future boiler investments. The integrated pyrolysis concept can be duplicated at several UPM mill sites, thus providing UPM with a major biofuel business opportunity.

Fortum owns and operates more than 20 combined heat and power (CHP) plants, many of them being suitable for biooil production. The company also owns and operates hundreds of small and mid-size heat-only boilers in industry and district heating networks. Many of those are fired by heavy fuel oil. Fortum will use existing biomass logistics for power plants in the supply of raw material for bio-oil. Raw material preprocessing will be integrated into the power plant fuel system and turbine plant too. The target is to gain high energy efficiency. The primary target is to provide biooil as an alternative way to minimize the CO₂ footprint of Fortum’s heat customers.

Metso will be able to market pyrolysis solutions to third parties in the global market.

4. EXPERIENCE FROM THE INTEGRATED PILOT PLANT
Metso has built the world’s first integrated pyrolysis pilot plant in Finland in cooperation with UPM, Fortum and VTT.

A 2 MW fuel fast pyrolysis unit has been integrated with Metso’s 4 MWth circulating fluidized bed boiler, which is at the company’s R&D centre in Tampere. This project is also partly funded by TEKES, the Finnish funding agency for technology and innovation. The joint venture started in 2007 and Fortum joined in August 2009. The pilot plant was finalized in early 2009 and hot commissioning took place during the spring and summer of 2009.

CLICK TO VIEW FIGURE 1: METSO’S R&D CENTRE IN TAMPERE, FINLAND
An indication of the expected organic liquid yields can be a failure in cyclone operation or a blockage. Reactions. An increase in the solids content in the liquid may indicate moisture or processing conditions, or the presence of catalytic materials. Any increase in water content may indicate a change in feedstock to be pyrolyzed. This correlation was also met with pilot plant test runs.

**CLICK TO VIEW FIGURE 2:** AN EXAMPLE OF PYROLYSIS REACTOR TEMPERATURE CONTROL

Since the pyrolysis reactor is integrated directly in the boiler, there is a need to determine how potential boiler temperature variations affect pyrolysis temperature. Figure 2 shows two intentional and one unintentional rapid boiler temperature disturbances. This shows that pyrolysis temperature control handles the rapid changes of boiler sand temperature smoothly. A sand temperature drop of 50 °C in just 20 minutes caused no noticeable disturbances in pyrolysis reactor temperature.

**5. PRODUCT QUALITY EXPERIENCE**

Quality follow-up along the entire chain (see Figure 3) from biomass processing via pyrolysis to bio-oil use, will both ensure the production of a consistently high-quality product and help to avoid possible problems during production.

**CLICK TO VIEW FIGURE 3:** QUALITY CONTROL CHAIN [4]

The main feedstocks for the pilot plant are forest residues and sawdust. The forest residues were prepared in UPM’s pulp mill at Rauma, Finland. Forest residues were collected within 50 km from the factory. The feedstock was dried at 40–50 °C to bring the moisture content down to 8 per cent by weight. It was also ground to particle sizes of under 5 mm. VTT has had good experiences with the fast Sartorius MA 45 moisture analysis device. Feedstock moisture is the main parameter which should be monitored constantly during processing. The main parameters to be measured with respect to liquid quality are water and solids content. Any increase in water content may indicate a change in feedstock moisture or processing conditions, or the presence of catalytic materials. An increase in the solids content in the liquid may indicate a failure in cyclone operation or a blockage.

A collection sample is analyzed using standard fuel analyses. An indication [5] of the expected organic liquid yields can be obtained by analyzing the volatiles/fixed carbon (Figure 4) of the feedstock to be pyrolyzed. This correlation was also met with pilot plant test runs.

**CLICK TO VIEW FIGURE 4:** YIELD OF ORGANIC LIQUIDS IN BIOMASS PYROLYSIS AS A FUNCTION OF FEEDSTOCK VOLATILE MATTER, PERCENTAGE BY WEIGHT BASED ON DRY FEED [5]

Karl Fischer (KF) titration analyzed the water content [6]. On-line equipment has been tested and modified. This on-line method does not typically measure density changes, which may cause minor errors in bio-oil analysis. On the other hand, density measurement devices do not function properly with bio-oils containing varying amounts of dissolved gas. Therefore, for quality monitoring, online KF seems to provide reliable information on changes in water content.

For particle sizing an online particle measurement system developed by Pixact Limited has been tested. Measurement is based on the high-magnification imaging of particles flowing through the measurement cell and an online image analysis procedure. Furthermore, a special algorithm will be used to detect particles in the images. In addition to size measurement, other properties such as shape parameters can also be analyzed. VTT compared the results with a commercial particle counter and a good correlation was obtained. These methods yield reproducible results, but the data are qualitative and intended to register sudden changes in the concentration of solids. The results also correlated well with the actual change in measured solids.

For laboratory measurements of water and solids content, bio-oil samples are taken at fixed intervals from condensers. Analyses are performed when needed. Figure 5 shows examples of the analyses of water and solids from a pilot test run.

**CLICK TO VIEW FIGURE 5:** AN EXAMPLE OF THE WATER AND SOLIDS CONTENTS OF BIO-OIL [5]

**5.1 CHEMICAL COMPOSITION OF PRODUCT LIQUIDS**

For quality follow-ups the amount of water and water-insolubles typically give sufficient information on product composition. Chemical characterization is carried out as needed. A solvent fractionation scheme based on water extraction using ‘sugars’ by the BRX method provides a fast and informative method for comparing various bio-oils or following the storage stability of bio-oils. Figure 6 presents the chemical composition of pilot bio-oils. As a comparison, a typical pine bio-oil from VTT’s Process Development Unit (PDU) is included.
6. COMBUSTION TEST EXPERIENCE

UPM’s focus is on using bio-oil as a substitute for both light and heavy fuel oil in heating and CHP plants. Fortum is also focusing on replacing fossil fuels. Test trials for both companies will be carried out at Oilon’s test facility.

Combustion tests performed earlier by Fortum and Oilon [2] in Saarijärvi have shown promising results in relation to combustion on a small-scale, or below 1 MW. Oilon has developed two model burners for bio-oils. Bio-oil from the pilot was combusted using the modified heavy fuel oil burner. Preliminary results were promising. The emissions in these short test runs were close to those of light fuel oil. With 4 per cent O2, CO emissions ranged from 0 ppm to 10 ppm, and NOx from 130 ppm to 320 ppm. Longer test runs will be carried out before summer 2010 with larger amounts of bio-oil. After demonstrating the replacement of heavy fuel oil use the focus of UPM will be on the replacement of light fuel oil.

Fortum will also be making a combustion test in one of its own district heating plants. A 1.5 MW gas and oil fired boiler has been converted to bio-oil test use. Test will take place in March 2010.

7. SUMMARY

The integrated pyrolysis concept enables high overall efficiency and bio-oil yields from the process. Char containing side stream and non-condensable gases is used in the adjacent boiler to produce heat and electricity.

When integrated with a fluidized bed boiler, pyrolysis fits well with Metso’s current product range. It enables customers to expand the fuel range of their fluidized bed boilers and to increase their value gained from biomass.

Integrated bio-oil production also fits well with the liquid fuel strategy of UPM and Fortum’s aim to become a CO2-neutral power and heat company. CO2-neutral bio-oil can be used to replace light and heavy fuel oil in heating and power applications. UPM is also interested in refining bio-oil for transportation fuel applications.

The first results from the integrated pilot plant have been encouraging. During the first season of test runs, more than 30 tonnes of bio-oil has been produced. The integrated concept has been verified as a reliable and flexible technology for the production of bio-oil. Compared with a stand-alone pyrolysis unit that uses a non-optimal small boiler for the combustion of the pyrolysis by-products char and pyrolysis gases, the integrated concept is easy and smooth to operate and operates at higher efficiency. For pyrolysis having a steady and smooth flow of input energy (in other words, boiler sand) to pyrolysis is a considerable advantage from the operator’s point of view.

Process quality control in the pilot plant included analyses of the water and solids content at fixed intervals. The results were available to the control room within an hour after sampling. This time was shortened when the online methods were in operation.

Major challenges include industrial preparation of biomass feedstock, removal of solids from the oil, and a technically and economically feasible combustion system. Solids contents in bio-oil have been below 0.2 per cent by weight using pine sawdust as feedstock without any additional stage for the removal of solids. Removal of solids from extractive-rich bio-oils, or forest residues, is more challenging and needs further development. A continuous centrifuge has been used successfully, and other methods will also be developed.

It may be possible to produce electricity, heat and bio-oil at the same boiler plant in the future.
REFERENCES

Experiences from the Construction of Olkiluoto 3 Plant

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1. FINNISH NUCLEAR PLANTS IN OPERATION
Finland has 125 years of experience in nuclear power reactor operation. This gives the country a good foundation for the construction and licensing of new nuclear power plants.

Two VVER-440 type plants are in Lovisa and two BWRs of Swedish (Asea-Atom) design are in Olkiluoto. The initial net power output of those power plants was 440 MW and 660 MW respectively. The power of the Lovisa reactors was increased in one step, and of the Olkiluoto reactors in two steps. Information on operating Finnish nuclear power plants is provided in Table 1.

CLICK TO VIEW TABLE 1: NUCLEAR POWER PLANTS OPERATING IN FINLAND

2. OLKILUOTO 3 PROJECT
The licensing of a nuclear facility in Finland involves three steps. The first is called ‘decision in principle’. This is a political step in which the government makes the decision that a new nuclear power plant is in line with the overall good of society and Finland’s parliament consents to the decision.

The decision in principle for a light water reactor of up to 1600 MW in Olkiluoto was approved by parliament in May 2002. Before this decision was made utility TVO had completed an environmental impact assessment. STUK had conducted a screening-type safety assessment of several nuclear power plant designs to conclude that alternatives are available for constructing a nuclear power plant that can meet Finnish safety requirements. The safety assessment process by STUK included discussions with interested vendors and resulted in design modifications that were proposed in the bidding phase.

The bidding process was started following the decision in principle, and the main contract for Olkiluoto 3 was signed in December 2003. Site preparations started soon after that, and the construction permit was issued in February 2005.

Olkiluoto 3 is the first EPR to be constructed, and it is a turnkey project by the Areva-Siemens consortium. Areva is responsible for the reactor island and Siemens for the turbine island.

3. STARTING NUCLEAR NEW BUILD AFTER A LONG SUSPENSION WAS DEMANDING
The start of the project was very slow because the vendor was not adequately prepared when the construction permit was granted. Parts of the detailed design and the working documents were not yet available and this hampered the planned progress in construction. It also took some time to find designers and experienced organizations for the construction and manufacturing.

There were major challenges to the implementation. They arose because of the new advanced design features of the EPR, the increased unit size and the application of new technologies. Many design features were implemented for the first time, and some of the manufacturing and other technologies had not been proven in tests or in practical applications.

It took some time to organize the construction of the reactor island but after an experienced company had been contracted and the working design was available the civil construction went ahead in a controlled manner. This happened about two years after the construction permit had been received. The schedule for the reactor island has slipped by about three years in total in the five years since construction began. The turbine island implementation has been more like ‘business as usual’ and has succeeded better.

In spite of the initial difficulties, the Olkiluoto 3 project has progressed reasonably well, and the negative impression created by the media, often based on misunderstandings of, and repeated blame by those who want to prevent new nuclear build worldwide, is not well founded. Olkiluoto 3 has provided valuable lessons for subsequent nuclear power plant construction in Europe and the USA.
4. HOW PREPARED WERE THE ORGANIZATIONS INVOLVED IN THE NEW BUILD?

4.1 VENDOR (AREVA)
The staff of nuclear island vendor Areva were much fewer compared with the number of designers at the time of the earlier construction. In particular, the number of designers was so low that it was not possible to determine the technical requirements from the EUR directly. In all of Areva’s earlier projects, EDF, the owner and licensee of French nuclear power plants, had played a key role as architect-engineer and had been responsible for managing the construction. Areva offered a new design that was based on extensive operating experience in France and Germany. Development of the design had taken almost ten years. Design work had been supported by the results of experimental research and also through the active involvement of the French and German regulatory bodies and their technical support organizations. However, the design was still at a conceptual stage and the parties involved did not recognize how much additional work was needed to complete it.

A major drawback, although not clearly recognized at the time of the signing of the contract, was that Areva did not enjoy the full benefit from its earlier experience as a nuclear power plant supplier. Areva signed a turnkey contract for Olkiluoto 3 and took responsibility for the reactor island without experienced partners and without having all the necessary competences. In all of Areva’s earlier projects, EDF, the owner and licensee of French nuclear power plants, had played a key role as architect-engineer and had been responsible for managing the construction.

Many of the experienced nuclear manufacturers that had contributed to the earlier Areva projects had left the business. It was necessary to find new subcontractors and to coach them in nuclear manufacturing.

4.2 LICENSSEE (TVO)
TVO has extensive experience of nuclear power plant operation and has implemented several modernization projects over the years, including the upgrading of power output at its plants. Throughout the 1980s and 1990s TVO cooperated actively with ABB Atom to develop an advanced new BWR design. It also conducted feasibility studies with other vendors and made an application to start new construction in the early 1990s. This application was rejected on political grounds by the Finnish parliament.

TVO’s call for tender received a major boost from the European Utility Requirements (EUR) that had been developed over more than ten years by the leading nuclear utilities in Europe. About 85 per cent of the technical requirements were taken directly from the EUR. Key people at TVO had worked in expert roles during the active involvement of the French and German regulatory bodies and had gained extensive knowledge about different nuclear power plant designs.

A difficulty for Areva was STUK’s unique regulatory approach, which had an early focus on the quality of structures and components. Furthermore, STUK had made arrangements to request expert support from organizations that were able to conduct testing and independent analysis (deterministic, PRA). STUK has been developing state-of-the-art national safety regulations since the 1970s, based on information received from extensive international cooperation. More than 20 years it had reviewed and assessed plans for the modernization of operating plants and also several feasibility studies for new construction. From such reviews it had gained extensive knowledge about different nuclear power plant designs.

4.3 REGULATORY BODY (STUK)
STUK had staff of adequate size and experience for reviewing the construction permit. Key persons in the organization had already been involved in the regulation of the construction of operating nuclear power plants.

STUK was able to rely on its own in-house competence for making safety assessments. It was able to review safety analysis and conduct evaluations of the design and management systems of the parties involved. It also had staff who could conduct the inspection of structures and components. Furthermore, STUK had made arrangements to request expert support from organizations that were able to conduct testing and independent analysis (deterministic, PRA). STUK has been developing state-of-the-art national safety regulations since the 1970s, based on information received from extensive international cooperation. More than 20 years it had reviewed and assessed plans for the modernization of operating plants and also several feasibility studies for new construction. From such reviews it had gained extensive knowledge about different nuclear power plant designs.

A difficulty for Areva was a unique regulatory approach, which had an early focus on the quality of structures and components. This approach had been learned by vendors from the Soviet Union and Sweden in earlier nuclear power plant construction projects in Finland but Areva was not used to such comprehensive assessment and inspection practice.

5. CONSTRUCTION SCHEDULE
The original target was to connect the plant to the grid about four years after the granting of the construction permit. The commissioning programme would then be completed for final turnover to the licensee 4–5 months later. Today the target is to start commercial operation at the end of June 2012. The nuclear island is thus about three years behind the original schedule. The main reasons for the delay are:

- A too ambitious original schedule for a plant that is the first of its kind and larger than any nuclear power plant built previously
- Inadequate completion of design and engineering work prior to start of construction
- Shortage of experienced designers
- Lack of experience in managing a large construction project
- Worldwide shortage of qualified equipment manufacturers

Areva not TVO adequately appreciated the key role of an experienced construction company in the success of the project. Furthermore, it seems that TVO was not adequately aware of the limitations in the capabilities of the potential vendors and the actual status of the available designs. The target set for construction time in the call for bids was therefore not realistic.
Construction of the turbine island, which is the responsibility of Siemens, has been a better progression. From the very beginning there has been close cooperation between Siemens and its subcontractor, an experienced construction company. This has resulted in good integration of design and construction work. Installations of the main equipment at the turbine island were completed about one year behind the original schedule, and the equipment is now waiting for commissioning to start.

6. THE ENVIRONMENT FOR NUCLEAR POWER PLANT CONSTRUCTION IS DIFFERENT FROM THAT OF THE 1970S

In planning and scheduling new build, it is necessary to recognize that circumstances in Europe and the USA are quite different from those of the 1970s, when most of the plants operating today were constructed.

Vendors of the 1970s were large experienced organizations that had comprehensive in-house capabilities for design and manufacturing. This reduced their dependence on subcontractors and management of the projects was more straightforward.

In the 1970s there was enough skilled manufacturing capacity in the market, and the large volume of construction facilitated the search for experienced project managers.

The need for design effort and for the qualification of design features was smaller then because designs were often based on work done previously in similar projects.

Since the first era of intensive nuclear power plant construction, vendors have lost much of their knowledge and skills because experienced experts have retired. Also, new types of competence are needed today for new technologies such as digital I&C systems.

The good name earned by a company in the past is no guarantee of success. More important is the experience and competence of individuals actually assigned to a project.

To begin new building, vendors need to establish a subcontractor network made up of companies with proven skills. Awareness of quality and an understanding of the nuclear safety culture must be taught to organizations that have no previous nuclear experience.

Management of work conducted by the subcontractors is a challenge in itself. The situation in Japan and Korea is evidently quite different.

Each design proposed in the bidding was an improvement on the original version that had been presented for tentative review during the decision in principle process.

8. NECESSARY TO MAKE SAFETY REQUIREMENTS AND THE REGULATORY PRACTICE CLEARLY UNDERSTOOD TO THE VENDOR TO AVOID UNCERTAINTIES IN LICENSING AND REGULATORY OVERSIGHT

EURs were used to present most of the technical requirements to potential bidders, but these did not include all the necessary national safety requirements.

The licensee and the regulator need to discuss at an early stage how the national safety requirements can be best presented in the call for bids. It became evident during construction that just making reference to the national requirements and the regulatory guides is not an adequate way to ensure that requirements are correctly understood by vendors. There should have been more extensive discussions in preparation for the Olkiluoto 3 project to agree on how to clearly express the national safety and quality requirements, and to describe the key features of the regulatory process in the call for bids.

To ensure smooth progress of the project, all parties (vendor, licensee, regulatory body) should be familiar with the licensing, regulatory oversight and inspection practices, both in the vendor country and the customer country. The differences and their implications should be discussed between the parties to allow optimized regulation of the project. The vendor needs to understand and take seriously the national regulatory practice.

In Finland, the regulatory practice is different to what Areva had experienced elsewhere. For example, a so-called construction plan is required that includes design and manufacturing information. A QC plan must be approved by both the licensee and STUK for all non-standard equipment in safety class 1 and 2 – other than valves, pumps and electric motors – before manufacturing or construction is allowed to start. Also inspections with hold points are made during construction and manufacturing.

9. PREPAREDNESS OF PARTIES FOR THE IMPLEMENTATION OF THE PROJECT HAS TO BE KNOWN BEFORE START

In order to avoid delays and difficulties in the implementation of
NUCLEAR POWER EUROPE: EXPERIENCES FROM THE CONSTRUCTION OF OHLKILUOTO 3 PLANT

For the effective management of the construction, both parties need to know how to schedule the work, what resources are needed and when, how the vendor can find competent contractors and how it should manage them, and how the licensee should conduct its oversight.

11. DESIGN MUST BE COMPLETED WELL BEFORE IMPLEMENTATION

Inadequate completion of design and engineering work prior to the start of construction is detrimental to implementation of the project on schedule. It delays the start of full-speed construction activities and leads to attempts to reschedule steps in manufacturing and construction. Such attempts make the management of the project complicated, and all delays put continuous time and cost pressures on the organizations involved.

In the Olkiluoto 3 project, detailed design was carried out too late. Delivery of construction plans for review and approval by STUK was often behind schedule. What was worse was that fixing the sometimes inadequate quality of design and engineering delayed the start of manufacturing and thus caused major difficulties for project management. Rotation of the initially poor construction plans for corrections and reassessment has been time and resource consuming. Insufficient construction plan quality also caused numerous unnecessary comments, and this has required extra time for the approval process. Several successive document revisions made subsequent inspections at vendor premises complicated.

The optimal timing of design consists of taking several steps towards greater detailedness. Conceptual design defines safety design criteria and their application in safety systems redundancies, diversity, physical separation and protection from external hazards. The layout of buildings, the process diagrams of main systems and key parameters for main equipment should be fixed. Conceptual design needs to be completed prior to bidding.

Basic design provides deterministic and probabilistic safety analysis, loads for the design of buildings and the specification of system parameters and limits for the protection system. Diagrams of the main systems, drawings of the main buildings and 3D drawings of the main fluid systems and structures should be presented.

Basic design needs to be completed before the application for a construction licence.

Detailed design provides the design specifications of all components and diagrams of all systems, drawings of all buildings, including 3D drawings of all fluid systems and structures. Detailed design needs to be conducted in parallel with the review of the construction license and must be completed no later than two years after the start of construction.

Working design provides shop drawings and plans for manufacturing the equipment, material specifications and quality control plans. For buildings it provides architectural drawings and specifications for construction. It needs to be completed well before...
the start of manufacturing or construction work where it is needed. It must also leave enough time for possible review by the licensee and regulatory body.

12. THE VENDOR MUST BE IN A FAIR PARTNERSHIP WITH THE SUBCONTRACTORS
To ensure good management of the subcontractor chains, it is important that in each call for tender on subcontracts the vendor clearly indicates and emphasises nuclear-specific practices and requirements. These could include a requirement to provide design documentation at an early stage for getting manufacturing approval from the licensee and regulatory body, a requirement that multiple quality controls and regulatory inspections be conducted during and after manufacturing, and expectations about safety culture.

If the nuclear-specific practices are not recognized and understood by the subcontractors at the time of the contract signing, difficulties are to be expected at a later stage.

13. VERIFICATION OF THE SUBCONTRACTOR’S CAPABILITIES BEFORE MAKING PURCHASE IS IMPORTANT
It has been noted in connection with many Olkiluoto 3 subcontracts that the actual competence of manufacturers and subcontractors was not easy to judge through auditing alone. Therefore an evaluation of the manufacturers’ abilities on the shop floor is important.

The licensee needs to have the means to ascertain whether issues specific to nuclear safety and quality management and respective controls are properly agreed in each contract between the vendor and its subcontractors.

Capabilities need to be assessed not only in the case of subcontractors that are newcomers to the nuclear field. In connection with the Olkiluoto 3 project it has been observed that a manufacturer having earlier experience of nuclear work had lost its control of quality management on the shop floor. In that case, workers tried to eliminate minor defects in major components without understanding what the potential harmful consequences were and did not ask for specialist advice before taking action. This led to serious consideration about whether re-manufacturing of the components in question was needed. Re-manufacturing would have caused an additional delay of more than a year to the startup of Olkiluoto 3.

14. LACK OF COMMUNICATION AMONG DESIGNERS CAN LEAD TO DISASTER
If design work is conducted by different organizations and in different places, or even in different countries, good coordination and communication among the designers is vital for a successful outcome. Lack of coordination and communication within the vendor consortium has been a problem area, especially in the early stage of the Olkiluoto 3 project and throughout the I&C design process.

The licensee and the regulator should audit and carefully assess the communication process and the adequacy of communication between those designers who are expected to interact to ensure a consistent design.

15. NEW ADVANCED SAFETY FEATURES ARE NOT EASILY IMPLEMENTED
Qualification of a new construction or manufacturing method may take time if it is not carried out before the start of a project. For example, new welding solutions were a challenge during the manufacture of the reactor pressure vessel. Full size welds were made and inspected in test pieces prior to the actual production of the new bi-metal welds that join the stainless steel safety-ends (which are of the same material as the coolant lines) to the vessel nozzles, made of carbon steel. The nozzles themselves were fitted to the vessel in a new geometry that allows in-service inspections. This required the development of an innovative automatic welding tool that was not easy to operate. The first production welds had quite large defects and repair welding was needed. Fortunately later welds succeeded well when the process had reached maturity.

Major difficulties were met in the manufacturing of the main coolant lines. The design target was to reduce the number of welds to a minimum. Achievement of specified material properties was difficult and several pieces had to be remanufactured before success was achieved. Another concern was over some of the shop welds that still had to be made in the main coolant lines. Micro-cracking, which the manufacturer had not faced before, was evident in the surface of the weld. Fortunately it was able to be demonstrated that the indications were only in the surface. They were removed by grinding and re-welding.

Many other large components for Olkiluoto 3 had to be remanufactured once or twice to achieve the specified quality and to ensure a 60-year lifetime. Among these were most of the pressurizer forgings, some reactor vessel internals, some main circulation pump casings and shafts, the high-pressure turbine shaft and the stator of the main generator.

16. THE LICENSEE IS RESPONSIBLE FOR THE SAFETY OF ITS PLANT WHEN IT BEGINS OPERATION
In order to bear its ultimate responsibility for safety, the licensee must have strong control of the project during construction. Turnkey and fixed-price projects are no exception. Similar quality control and auditing arrangements are needed regardless of the contract type. It is therefore necessary for the roles and responsibilities of the licensee and vendor to be specified for the construction phase.

The licensee should conduct its own safety assessment to verify that the plant and its systems, structures and components are licensable. For this it needs a requirement management system of its own and an independent capability to verify and prove that all requirements
are met. The licensee must also have a system for reporting and resolving all non-conformances that are identified in the audits and quality inspections.

The experience from Olkiluoto 3 is that one can expect thousands of small and large non-conformances. Therefore it is necessary to have unambiguous requirements for the classification of non-conformances.

17. LICENSSEE MANAGEMENT TEAM NEEDS TO BE COMMITTED TO THE IMPLEMENTATION OF A STRONG QUALITY SYSTEM

The system for quality management needs to provide transparent links between safety and quality classes, and emphasize the general requirement on application of respective nuclear-specific quality standards. The licensee management team has to communicate its requirements and expectations about quality to all parties. The experience from Olkiluoto 3 also indicates that it would be worthwhile for the licensee management to require that the vendor uses proven state-of-the-art technology in manufacturing and construction and selects manufacturers with proven good performance. The licensee management should not simply accept low-cost technologies or manufacturers that barely meet the minimum agreed quality requirements.

18. THE SAFETY CULTURE NEEDS TO HAVE BEEN DEVELOPED BEFORE CONSTRUCTION TIME

A strong message and transparent actions and decisions are expected from the management teams of the vendor and the licensee to promote a culture of safety. Safety and quality have higher priority than costs and schedule. This needs to be demonstrated in, for example, the choice of qualified subcontractors, the choice of state-of-the-art tools and methods, uncompromising compliance with agreed requirements, and walk downs by management.

A questioning attitude is needed at every level and in every organization, including the licensee, vendor and all subcontractors. Workers should be encouraged to report potential safety concerns to their supervisors and all questions and concerns raised by them need to be responded to properly. One reason is that a concern by a worker could be based on a misunderstanding.

Each person involved in the project needs to understand the safety significance of their work. This promotes personal responsibility.

19. CLOSE REGULATORY OVERSIGHT HAS BEEN FOUND TO PROMOTE QUALITY OF CONSTRUCTION

Throughout the Olkiluoto 3 project there have been multiple quality controls carried out by the manufacturers themselves, by Areva, an independent third party, TVO and STUK. Therefore the product deviations have generally been detected with high sensitivity. Nevertheless in some situations the QC inspectors of the manufacturer, vendor, and licensee have evidently faced great economic pressures and have not been strong enough to enforce stoppages of work or the making of necessary timely corrections. This has happened even when the work has not progressed as expected and the parties have recognized what deviation has occurred from the specified target. In such a situation an intervention by a regulatory inspector is needed.

A stringent regulatory approach and inspections are thus needed to verify that new manufacturing techniques and new types of equipment meet the specifications set by the designer.

20. CONCLUSIONS

Starting new build is demanding because a lot of experience and resources have been lost from the nuclear industry. Adequate time has to be allocated to good preparation of the project before actual construction starts. This means:

- Making a design as early as needed for smooth construction
- Qualifying the new design features and technologies
- Building competent organizations
- Specifying the responsibilities of parties
- Ensuring the availability of qualified designers, constructors and manufacturers to implement the project
- Resolving potential regulatory uncertainties

During the construction of Olkiluoto 3, STUK has concluded that close monitoring and oversight by both the licensee and the regulatory body is necessary to ensure the achievement of the specified quality, in other words, meeting the technical standards and criteria that the vendor has specified and that have been approved as part of the licensing and design documents. Encouraging progress has been made during the project, and after teething problems the construction has proceed well. However, in the first piping installations at the reactor island in October 2009, enforcement actions were again needed to make the welders follow the specifications given in the procedures.

While there have been many non-conformances and many instances of the need to re-manufacture, the quality awareness and proactiveness of the licensee and the manufacturers have been reasonably good. Corrective actions have been taken in line with the QA/QC practices specified for the project.

The final quality of Olkiluoto 3 structures and components has not been compromised although in some cases achieving and proving the expected quality has required special efforts. These have included extensive and time consuming tests and inspections to prove that required standards have been met; extensive new analysis; and re-manufacturing of some equipment.

The observed difficulties at the construction stage have not raised concerns about how safe the power plant will be when it is ready to operate.
Plant Life Extension of the Krško Nuclear Power Plant in Slovenia

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ABSTRACT
In the past 15 years generic ageing management processes have been developed and implemented in the nuclear industry to enhance the identification and ageing management of important systems, structures and components (SSCs). Long-term ageing management is addressed through implementation of these processes that assure ageing is managed for SSCs that are important to safety so that there is reasonable assurance that plant safety is maintained throughout the extended life of the plant.

In the US this is ensured through implementation of the Maintenance Rule (10CFR50.65) for the ageing management of active component functions and through the License Renewal Rule (10CFR54) for the ageing management of passive component functions. The generic process for performing ageing management under 10CFR54 [1] involves three steps: performing plant scoping/screening, performing ageing management reviews (AMRs) and evaluating time-limited ageing analyses.

At the international level, the International Atomic Energy agency (IAEA) has published guidelines that include ageing management objectives with similar goals as the regulations that have been implemented in the US. The generic regulation-based methodologies as developed in the United States or by the IAEA are compatible with the rules and regulations at all nuclear facilities in the world.

This paper describes how these processes and methodologies were implemented at the Krško nuclear power plant in Slovenia. It outlines the project organization and tools that were successfully implemented. It finally provides highlights of the results obtained for each phase of the process, which was completed in 2008 and which is the basis of the application for a plant life extension of 20 years.

1. INTRODUCTION
All nuclear power plants have implemented some form of long-term ageing management at their facilities. However, methodologies have been developed that can provide enhancements to the existing ageing management plans.

Comprehensive long-term ageing management strategies consider the role of every SSC in the nuclear power plant and assess how ageing can prevent them from performing those roles. Many nuclear power plants have not yet implemented a long-term ageing management strategy or programme. These plants typically use existing maintenance and inspection programmes to manage plant ageing.

While maintenance and inspection have not been traditionally called ageing management programmes (AMPs), they perform activities that are credited with the management of ageing. These activities have been performed for many years, and many of these programmes exist as a result of commitments to specific regulations, for example in-service inspection.

Other programmes exist because they have been identified by standards or industry best practices. Operating experience provides feedback when failures occur so that enhancements to programmes can be developed through the corrective-action process. For the purposes of this paper, these programmes are termed experience-based ageing management.

While experience-based ageing management has served the industry well and will continue, experience suggests that many gaps have been identified when a long-term ageing management strategy is implemented. These gaps include missing programmes, key components that are experiencing ageing but are not covered by any programme, deficient or outdated techniques being used in existing programmes, and enhancements in the acceptance criteria for the programme.

Additional methodologies have been developed to identify gaps in experience-based ageing management and to confirm that the existing ageing management is sufficient. These methodologies combine to provide a comprehensive long-term ageing management strategy. While the ultimate goal of these methodologies is the same, that is, managing the ageing of plant SSCs to assure safety and cost efficiency, their focus and stakeholders are different, so there are differences in the specific methodologies. These additional methodologies can be defined as economy-based and regulation-based methodologies.
Experience-based methodologies rely on the accumulated operating experience and shared knowledge of the industry to ensure ageing management is focused on the areas in which ageing has been experienced.

Economy-based methodologies implement risk and economic considerations into the ageing management process with the focus given to the ageing that has the highest impact on plant availability and reliability.

Regulation-based methodologies focus on the impact ageing may have on plant safety. Obviously the regulation-based methodologies are also the focus of safety regulation, which is being implemented throughout the nuclear industry. This paper provides an overview of regulation-based ageing management processes and methodologies and how those processes were implemented at the Krško nuclear power plant in Slovenia.

2. GENERIC REGULATION-BASED METHODOLOGY FOR AGEING MANAGEMENT

Historically all plants in the world have followed the experience-based ageing management practices that were described briefly earlier in this paper. However, in the past 10–15 years there have been additional generic processes implemented in the industry that enhance the identification and ageing management of important SSCs. These generic regulation-based methodologies include the Maintenance Rule and License Renewal Rule.

The Maintenance Rule is a regulatory programme, imposed via 10CFR50.65, that provides oversight of the preventative maintenance that is performed at the plant. The regulatory focus is plant safety, therefore the scope of the Maintenance Rule is limited to the SSC functions that are important to safety, including safety-related (SR), non-safety related (NSR) supporting SR, SSCs supporting emergency operating procedures and SSCs whose failure could cause a scram.

For those components in scope, preventative maintenance is assessed to ensure that the maintenance is supporting an overall goal of continuous improvement. To accomplish this objective, specific system performance goals are established and periodically measured and trended.

When system performance degrades, the Maintenance Rule process requires actions to be implemented to reverse the trend. In this manner, the Maintenance Rule simply provides for regulatory oversight to ensure that the experience-based preventative maintenance process is adequately implemented from both scope and process perspectives.

In the Statements of Consideration to the License Renewal Rule [2], the US Nuclear Regulatory Commission (USNRC) states that as a result of the continued applicability of the Maintenance Rule and regulatory requirements, the active functions of SSCs will be reasonably assured in any period of extended operation. However, in this same document, the USNRC provides reasons why the Maintenance Rule does not provide sufficient ageing management of long-lived, passive SSCs. Two practical examples are safety-related structural components, such as passive structural supports and electrical cables. Therefore, the focus for licence renewal is the long-lived, passive SSCs and the design-basis calculations that have a time-limiting aspect.

The two regulations, taken together, provide regulatory oversight of the ageing management processes that ensure both the active and passive functions of SSCs that are important to plant safety. These regulations also provide the regulatory basis to ensure long-term operation of the nuclear power plant.

The generic process for performing ageing management under 10CFR54 involves three steps: performing plant scoping/screening, performing (AMRs) and evaluating TLAs.

The scope of SSCs within the scope of the ageing management process includes SSCs that are SR, NSR supporting SR, and SSCs supporting each of five regulated events determined by the USNRC to be important to safety (fire protection, environmental qualification, station blackout, anticipated transients without scram, and pressurized thermal shock).

The components determined to be within scope require an AMR. AMRs are generally performed on a system basis. For each system, the ageing management process includes the following activities:

- Determine component materials of construction
- Identify environments in which these components reside
- Determine the ageing effects for the combinations of material and environment
- For all components and all ageing effects, either confirm that plant programmes exist that manage ageing, modify existing programmes or develop new programmes
- Validate results with plant-specific and industry operating experience

Implementing the ageing management process shown above has identified that there are gaps in ageing management that exist at all plants that have implemented the process. There are many reasons for these gaps but typical ones include SSCs not being within the scope of an AMP, the programme does not adequately perform ageing management, for example incorrect inspection methods for the ageing effect concerned and lack of trending where appropriate, or there are no AMPs in place.

Existing programmes are credit with managing ageing to the maximum extent possible. Many programmes are credited with managing ageing with no changes or programme modifications necessary. Typical existing AMPs include in-service inspection (code-required inspections), water chemistry monitoring and flow-accelerated corrosion monitoring.

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Conversely, industry ageing management experience has shown that most plants need to modify some of their existing programmes or implement new AMPs. Examples of typical modified and new programmes include underground-piping external surface inspections, structures and structural components inspections and cables and connections inspections.

The final step in the generic process is to locate, review and, in some cases, revise plant analysis and calculations that have a time-limited aspect, for example the original plant design included in the basis consideration of the number of fatigue cycles that certain components could experience during plant life. These fatigue cycles are typically monitored by counting the number of transients that the plant has experienced and comparing those against limits that are typically contained in the plant United Final Safety Analysis Report, or in design-basis documentation that supports the information in the UFSAR. The calculations supporting the UFSAR criteria are TLAAs and must be evaluated against the actual number of transients for life extension. In cases where the actual number of transients may be exceeded before the period of extended operation is over, additional analysis is needed to verify that the design basis for fatigue will not be violated.

2.2 USNRC REGULATIONS VERSUS IAEA GUIDELINES
Long-term ageing management is addressed through implementation of processes that assure ageing is managed for SSCs that are important to safety so that there is reasonable assurance that the active and passive component functions are maintained. In the USA, this is ensured through implementation of the Maintenance Rule (10CFRSO.65) for ageing management of active component functions and through the License Renewal Rule (10CFRS4) for ageing management of passive component functions. The IAEA has published guidelines that include ageing management objectives that have similar goals as the regulations that have been implemented in the US. Specifically, the guideline governing periodic safety reviews [3] states that each SSC should be assessed against its design basis to confirm that ageing has not significantly undermined the design-basis assumptions.

Additional guidelines [4] have been issued subsequently to the periodic safety review that provide additional detail for long-term operation of nuclear power plants with regard to ageing management. While there are differences in the specific text between the IAEA and USNRC documents, the intent of the USNRC and IAEA documents is the same: to provide for the long-term ageing management of the important portions of the nuclear plant. Therefore the generic regulation-based methodologies discussed in this portion of the paper are compatible with the rules and regulations at all nuclear facilities in the world. In fact, this generic approach has been comprehensively implemented in ageing management projects in Spain and Slovenia, and through the licence-renewal processes in over half of the plants in the USA.

2.3 CONCLUSIONS ON THE REGULATIONS-BASED APPROACH
While experience-based ageing management provides an excellent methodology for managing ageing issues during the early years of plant life, the nuclear industry has recently successfully implemented generic methodologies throughout the world that provide reasonable assurance that plant ageing will not prevent the plant from performing important functions for long-term operation. Long-term operation includes time-periods extending beyond the initial design basis of the plant.

For most plants, the initial design basis was 40 years. The methodologies described in this paper have been successful in providing the bases for extending the initial operating period of the plant. For example, more than 50 plants in the United States, or over half of the nuclear fleet, have successfully justified plant operation for an additional 20 years. Spanish plants have had similar successes, although Spanish utilities are negotiating about the details of the extended period of operation. The Krško nuclear power plant in Slovenia is having the results of its process reviewed by the Slovenian regulatory body, with the anticipation of successful long-term operation. All of these successes implemented processes that are similar to the generic regulation-based methodologies described above.

The focus of the regulation-based methodologies is satisfying the rules that are implemented by the authorities to ensure public safety and health. While this focus is integral to the long-term operation of the plant, it is also important to the utility owner-operator to ensure that ageing does not significantly impact the reliability and availability of the plant.

3 IMPLEMENTATION OF THE METHODOLOGY AT THE KRŠKO NUCLEAR POWER PLANT

3.1 HISTORY OF AGEING MANAGEMENT PROGRAMME (AMP)
Krško performed its first periodic safety review (PSR) and recognized a need to develop an AMP. Since there was no existing AMP, NEK agreed with the regulatory body to develop a programme in accordance with the PSR and to establish scoping and screening process and results based on the USNRC methodology [10CFR54 License Renewal Rule].

The initial scoping and screening was finalized in 2003. Based on a request from the regulatory body for the next step to be to perform an AMR and the review of TLAAs analyses, NEK started with the AMP in 2006. The main goal was to develop an AMP similar in content and scope to the USNRC License Renewal Application for the AMP, including any associated changes to licensing documents.
An extensive review was conducted over a period of more than two years and was completed at the end of 2008. The review findings resulted in several plant programme changes, development of some new programmes, changes in different plant processes and also some modifications. The developed action plan was implemented in 2009 and 2010. There are ongoing licensing processes at the Slovenian regulatory body to approve the AMP as an action of the PSR and to approve life extension of 20 years (2043). NEK expects to receive this approval in 2010.

3.2 GENERAL PHASES OF THE PROJECT
The main phases of the Krško AMP were scoping and screening, AMR, TLAA review and implementation of an action plan. Each of these phases is described in the following sections.

3.3 SCOPING AND SCREENING
The purpose of the scoping and screening process was to determine the plant systems and structures that are within the scope of the AMP. The SSC’s within scope were defined as:

- Safety-related
- Non-safety related but whose failure could adversely impact a safety-related SSC
- Those that relied on in-plant evaluations to demonstrate compliance with regulations concerning fire protection, environmental qualification, pressurized thermal shock, anticipated accidents without scram, or station blackout.

All plant systems and structures were reviewed against the scoping criteria, and the intended functions of the system or structure were defined and documented when any criterion was fulfilled. For systems and structures that were determined to be in-scope, component screening established which components were subject to AMR according to screening criteria defined in the License Renewal Rule [1].

The screening process has three successive steps that identify those components subject to AMR on the basis of whether they (i) support the system-intended function; (ii) are passive; and (iii) are long-lived, in other words not subject to replacement. Components that do not fulfill all of these criteria are not subject to the AMR.

3.4 AMR
The purpose of the AMR was to provide reasonable assurance that component ageing will not prevent a component from performing its intended function(s) are ageing effects requiring management (AERM). The primary reference for identification of AERMs was NUREG-1801, the Generic Ageing Lessons Learned (GALL) Report [5]. In some instances, the GALL Report does not include material-environment combinations that exist at Krško. In those instances, the AERMs were identified through project-specific research.

The GALL Report was used to guide the ageing management evaluation process. It contains a comprehensive description of AMPs and a generic evaluation of SSC ageing effects. The USNRC has determined, based on accumulated operating experience and laboratory results, that certain programmes can be credited generically with managing ageing when certain generic conditions (materials and environments) exist in the plant. Where a plant can validate consistency with the GALL Report, similar conclusions can be reached on a plant-specific basis.

NEK evaluated each of the systems and structures in scope using the GALL Report as the basis for identifying AMPs for managing the identified AERMs for each component type. In the case of the electrical discipline, components were evaluated generically based on commodity type. The programmes credited with managing each AERM for components that are subject to AMR are documented in AMR reports.

Each of the plant-specific programmes that are credited with managing component ageing was evaluated for consistency with the generic programme described in the GALL Report. Where the programme was consistent with the GALL Report, no changes to the existing NEK programme were identified. Where the programme was not consistent with the GALL Report, programme enhancements were identified. If a programme in the GALL Report is credited with managing ageing but did not exist, a new programme was required and the attributes of the GALL Report were used as bases for the new programme. Each of the plant-specific programme evaluations against the GALL Report were documented in a separate project report.

Plant documents, such as plant procedures and controlling programme documents, were marked up to describe the proposed changes to the documents consistent with the changes needed for implementation of ageing management. In cases where there was no existing programme at NEK, a draft of a new programme was prepared.

Several plant processes required enhancement in order to implement ageing management as a living process into the future daily operations of Krško.

First, the Krško UFSAR was revised to incorporate any changes affected by ageing management. The USFAR update also included a USFAR Supplement that describes the AMPs that are credited with managing SSC ageing. The plant technical specifications were also reviewed and updated. Additionally the plant master equipment
database maintenance and work order processes were updated to add database fields related to ageing management, along with instructions for data maintenance. Finally, the plant design change process was revised to consider the impact that design changes may have on ageing management commitments and corresponding licensing actions.

3.5 TLAAs Review
The purpose of TLAAs as required under 10CFR54 is to identify and evaluate plant-specific ageing analyses that are explicitly based on the current operating term of the plant. Once a potential TLAAs has been identified, the specific issue is screened using the six criteria in the definition of a TLAAs. The process to identify the TLAAs is defined in the guidance provided in NEI 95-10: Industry Guidelines for Implementing the Requirements of 10CFR Part 54 – The License Renewal Rule.

For Krško, the calculations and evaluations that could potentially meet the six criteria of 10CFR54.3 were identified by searching current licensing basis documents including: NIE technical specifications, NIE USAR, licensing correspondence documents, design-basis documents, applicable Westinghouse analyses and reports for steam generator replacement and power uprating, and other company reports and applicable reactor vessel capsule surveillance reports. Industry-generic documents that list generic TLAAs were also reviewed to provide completeness of the plant-specific list.

Potential TLAAs related to civil structures and to EQ equipment were identified. To identify actual TLAAs, all of the potential TLAAs were evaluated against the six criteria in the definition of TLAAs in 10CFR54.3. Then the actual TLAAs were identified and further assessed. The main TLAAs that were assessed were the following:

- The reactor coolant loop piping and reactor coolant system (RCS) components fatigue
- The auxiliary class 1/2/3 piping fatigue
- The environmental fatigue evaluations according to NUREG/CR-6260
- The reactor vessel bellline fluence evaluation and the reactor pressure vessel irradiation embrittlement
- The impact of thermal ageing on stainless steel welds and cast material

The main conclusions of the fatigue assessment is that the applicable fatigue analyses of reactor coolant loop piping and reactor coolant system components have been reviewed and follows RCS transients only with the exception of the pressurizer bottom shell and surge nozzle. For the RCS transients, the number of occurrences expected over 60 years of life is widely covered by the number of cycles assumed in design analyses.

Therefore the fatigue analysis results and usage factors remain applicable for the 60-year life extension. The same overall conclusion was drawn for the auxiliary class 1 piping lines and further recommendations were developed for a few locations subject to specific thermal cycling, for example the surge or RHR letdown lines. The fatigue evaluations generally demonstrated the need to have an accurate fatigue monitoring system in place to support the life extension.

The assessment of the ‘end of life’ fluence and its effects on the reactor pressure vessel embrittlement has demonstrated that the adjusted reference temperatures are moderately impacted by 60 years of operation in comparison with 40 years of operation. Finally, the assessment of the thermal ageing impact in the RCL piping welds and base material, and in the cast stainless steel components such as the reactor coolant pump casing after 60 years of plant operation shows sufficient toughness to validate the applicability of the leak before break considerations or the applicability of the ASME Code Case N-481 in the case of the RCP casing.

3.6 IMPLEMENTATION OF AN ACTION PLAN
The main goal of the AMP was to implement the PSR task and to update the current licensing bases for plant life extension of 20 years. The review phase was completed at the end of 2008. All the findings and required actions were summarized in an AMP action plan document that defined responsibilities and a schedule for each implementation task.

To ensure timely and comprehensive completion of all tasks, the whole action plan was transferred to the plant corrective-action programme. All programme changes, development of new programmes, changes to different plant processes, modifications and other changes were included in this implementing process.

As of the writing of this paper in May 2010, nearly all action plan tasks had been implemented. This licensing process began in March 2009 and has been conducted with independent authorized institution review and oversight. After independent review authorization, a licensing amendment will be delivered to the regulator for the final approval of AMP and plant life extension.

4. CONCLUSIONS
All nuclear power plants have implemented some form of long-term ageing management at their facilities. However, methodologies have been developed recently that can provide enhancements to the existing ageing management plans. Comprehensive long-term ageing management strategies consider the role of every SSC in the nuclear power plant and assess how ageing can prevent corrective action programme. All programme changes, development of new programmes, changes to different plant processes, modifications and other changes were included in this implementing process.
ageing of plant SSCs to assure safety and cost efficiency, their focus and stakeholders are different. Therefore there are differences in the specific methodologies.

Three specific methodologies were introduced in this paper: experienced-based, economy-based and regulation-based. However, the regulation-based methodologies were discussed in greater detail in this paper and the implementation of the methodology on a plant-specific basis at NEK’s Krško nuclear power plant in Slovenia was described.

While historical methodologies have served the industry well during the early years of plant operation, industry experience is that these methodologies must be supplemented with additional long-term ageing management strategies to ensure the goal of long-term operation is achieved.

This paper provided some basic information to assist the reader to obtain a basic understanding of the regulation-based methodologies that the industry is using to address long-term operation of nuclear power plants.

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ESBWR – A European Solution

ABSTRACT
Nuclear reactor technology has continued to advance and improve since the first plants were put into service more than 50 years ago. Today’s plants can be categorized as ‘advanced’ plants utilizing the US Department of Energy naming conventions: Generation III, which describes advanced light water reactors with improved safety and control systems, Generation III+, which describes evolutionary designs that use passive safety systems to shut the plant down and Generation IV, which describes proliferation resistant plants with minimal waste.

The ESBWR is a Generation III+ plant design with passive safety systems and natural circulation to simplify operation with improved economics. The ESBWR technology has evolved and built on the successes of the past, along with the construction and operating experience of the ABWR, with resulting improvements in safety, the cost of operational performance and fuel flexibility.

The ESBWR reactor technology has been under extensive formal licensing review in the United States since 2005. Through that process, many detailed technical challenges have been dealt with forthrightly, addressed and solved, so that today no open technical issues remain. That experience can now be directly applied in Europe.

Many of the technical challenges being raised across Europe in the areas of digital instrumentation and controls, and structural component design have already been addressed and solved through the USNRC licence reviews. Fortunately there are positive signs that some standardization of regulatory requirements is occurring between the US and a number of European countries.

Additional European requirements are simultaneously being addressed in discussion with European utility customers and their regulators. The ESBWR is a true Generation III+ technology that can provide European customers with a novel and cost-effective solution, offering full passive safety systems that do not require any operator action or AC power for at least 72 hours to safely shutdown.

1. GENERATION III ABWR
The US Department of Energy has categorized today’s advanced light water reactor reactors with improved safety and control systems as Generation III. The advanced boiling water reactor (ABWR) is a Generation III reactor that was developed incorporating a careful blend of the best features of worldwide operating BWRs, available new technologies and improved construction techniques. Safety improvements were also incorporated, along with special attention paid to systematically reducing capital cost and features to significantly ease maintenance.

CLICK TO VIEW FIGURE 1: ABWR PLANT CUTAWAY

1.1 ABWR SAFETY ENHANCEMENTS
Recognizing the desire for enhanced safety, one of the goals of GE and Hitachi for the ABWR was to reduce calculated core damage frequency by an order of magnitude relative to then currently operating BWRs. The most important design feature contributing to this goal is the adoption of reactor internal pumps (RIPs). These vessel-mounted pumps eliminate large, recirculation piping on the vessel, particularly involving penetrations below the top of the core elevation. These make possible smaller capacity pumps for the emergency core cooling system (ECCS) network to maintain core coverage during postulated loss-of-coolant events.

The ABWR ECCS network was designed as a full three-division system with both a high and low-pressure injection pump, and heat removal capacity in each division. For diversity, one of the systems, the reactor core isolation cooling (RCIC) system, includes a steam-driven, high-pressure pump. Transient response was improved by...
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ESBWR features and licensing status
designing three available high-pressure injection systems in addition to feedwater. The adoption of three on-site emergency diesel generators to support core cooling and heat removal, as well as the addition of an on-site gas turbine generator, reduces the potential for ‘station blackout’. The balanced ECCS system has less reliance on the automatic depressurization system (ADS) function since a single, motor-driven high-pressure core flooder (HPCF) can maintain core safety for any postulated pipe break.

Response to Anticipated Transients Without Scram (ATWS) is improved by the adoption of fine-motion control rod drives (FMCRDs), which allow reactor shutdown either by hydraulic or electric insertion. In addition, the need for rapid operator action to mitigate an ATWS is avoided by the automation of emergency procedures such as feedwater runback and standby liquid control system (SLCS) injection.

Core damage frequency has been calculated at $1.6 \times 10^{-7}$/year, which is more than a factor of ten better than the BWR/6 design and also below most advanced competing PWR designs. Furthermore the ABWR also improved the capability to mitigate severe accidents, even though such events are extremely unlikely. Through nitrogen inerting, containment integrity threats from hydrogen generation were mitigated. Sufficient spreading area in the lower drywell, together with a drywell flooding system, provides coolability of postulated core debris. Manual connections make it possible to use on-site or off-site water systems to maintain core cooling. Finally, to reduce potential off-site consequences, a passive, hard-piped containment heat removal capability has been regained, the operator was designed with the understanding that following a severe accident, the whole body dose consequence at the calculated site boundary is less than 25 Rem. The probability of such an occurrence is calculated to be about $10^{-9}$/year.

### 1.2.1 INERTED CONTAINMENT

The ABWR containment is normally inerted with nitrogen containing less than 3.5 per cent oxygen. Therefore any potential for hydrogen burning or detonation after a severe accident is avoided.

### 1.2.2 LOWER DRYWELL FLOODER

The lower drywell flooders is designed to flood the lower drywell with water from the suppression pool should core melting occur that could, in an extreme case, result in subsequent vessel failure. Several pipes run from the vertical pedestal vents into the lower drywell. Each pipe contains a fusible plug valve connected by a flange to the end of the pipe that extends into the lower drywell. In the unlikely event that molten corium flows to the lower drywell floor, the fusible plug valves open when the drywell atmosphere temperature, and subsequently that of the fusible plug valve, reaches 260 °C.

The fusible plug valve is mounted in the vertical position with the fusible metal facing downward to facilitate the opening of the valve when the fusible metal melting temperature is reached. When the fusible plug valves open, suppression pool water will be supplied through the system to the lower drywell to cover the corium, quench the corium and remove corium decay heat. The result will be a reduced drywell temperature and less pressure from non-condensable gas generation. This will reduce the chance of overpressurizing the containment and increasing leakage. The lower drywell flooders is a passive injection system. No operator action is required.

### 1.2.3 CORIUM SHIELD

The bottom of the lower drywell contains two features to mitigate against continued core-concrete reactions after quenching by the passive lower drywell flooders. The first of these is the use of non-limestone aggregate concrete, or the so-called ‘basaltic concrete’. This minimizes any further production of carbon-based non-condensables, such as carbon monoxide (CO) and carbon dioxide (CO₂). In addition, the drywell sumps are covered with refractory oxide bricks to prevent intrusion of molten corium into the sumps.

### 1.2.4 CONTAINMENT OVERPRESSURE PROTECTION SYSTEM

If an accident occurs which increases containment pressure to a point where containment integrity is threatened, this pressure will be relieved through a line connected to the wetwell atmosphere by relieving the wetwell atmosphere to the plant stack. Providing a relief path from the wetwell airspace precludes an uncontrolled containment failure. Directing the flow to the stack provides a monitored, elevated release.

The relief line, designed for about 1 MPag, contains two rupture disks in series which open at a pressure above the design pressure but below the Service Level C capability of the containment. If over-pressure occurs, the rupture disks will open and pressure is relieved in a manner that forces escaping fission products to pass through the suppression pool. Relieving pressure from the wetwell as opposed to the drywell takes advantage of the decontamination factor provided by the suppression pool.

After the containment pressure has been reduced and normal containment heat removal capability has been regained, the operator...
can close two normally open air-operated valves in the relief path to re-establish containment integrity. Initiation of the pressure relief system is totally passive. No power is required for initiation or operation of the pressure relief function for an indefinite period.

1.2.5 AC-INDEPENDENT WATER ADDITION

Two fire protection system pumps are provided on the ABWR. One pump is powered by AC power, the other is driven directly by a diesel engine. A fire truck can provide a backup water source. One of the fire protection standpipes is cross-connected to the residual heat removal injection line to the reactor vessel through normally closed, manually operated valves. From this line, fire protection water can be directed to the reactor vessel after the reactor vessel has been depressurized. Fire protection water can also be directed to the drywell spray header to reduce upper drywell pressure and temperature.

Analyses of the dominant severe accident sequence, which is a low-pressure core melt following a station blackout, shows that the containment overpressure pressure system protection will not be reached for more than 24 hours. In addition, the conditional containment failure probability, defined as the loss of containment as a fusion product barrier, was calculated to be 0.2 per cent, far less than the goal of 10 per cent set by the US Utility Requirements Document and USNRC guidelines.

2. GENERATION III+ (ESBWR)

Advanced light water reactor reactors that fully employ passive safety systems have been categorized as Generation III+. The ABWR, as a Generation III type, employed many passive safety features and systems as described above. The ESBWR draws on proven ABWR technology and design, and furthers the use of natural and passive safety systems. It is able to safely shutdown without any operator action or AC power supply for at least 72 hours.

CLICK TO VIEW FIGURE 2: ESBWR PLANT CUTAWAY

In the late 1980s GE began to design a natural circulation BWR featuring passive safety systems. This effort produced a 670 MW e reactor known as the simplified BWR (SBWR). The development programme was later redirected to design a larger reactor that used economics of scale, proven technology and components from the ABWR to create a new reactor at reduced capital cost. Relative to the ABWR, the simplifications include the elimination of reactor internal pumps to circulate reactor coolant, and also the elimination of active safety system pumps.

The ESBWR's expected lifecycle economics are also improved through tangible reductions in permitting, licensing, construction and operating costs. The design reduces the number of systems and components, while simultaneously using processes and technologies from the already developed and operationally proven ABWR. In addition to reducing the technology risk, this approach keeps first-of-a-kind and follow-on development costs low while still optimizing the use of the latest technology.

The use of the ABWR design and its applicability to the ESBWR has been a key benefit for the design team. The fact that the ABWR design contains many technological advances and is proven in terms of construction schedule, cost and operation has allowed the design team to benefit from this knowledge. Applying design concepts with the confidence that proof from operation brings.

2.1 ESBWR, SIMPLIFIED PLANT DESIGN

The ESBWR achieved its basic plant simplification with natural circulation and passive safety systems and by incorporating innovative adaptations of operating plant systems into the plant design, in other words, combining shutdown cooling and reactor water cleanup systems. The new systems are described below.

The reactor building is reduced in volume. Further nearly all safety systems are now located in containment or directly above it, which allows significant reductions in the volume and footprint of other buildings. The ESBWR design benefited greatly by first-of-a-kind engineering performed for the ABWR and the detailed design and testing of the SBWR. Technology common to the ABWR and the ESBWR is:

- Materials and water chemistry
- Fine motion control rod drives
- Multiplexing and fibre optic data transmission
- Control room design
- Plant layout for ease of maintenance
- Reinforced concrete containment technology
- Pressure suppression horizontal vent
- Radwaste technologies

The ESBWR draws on proven ABWR technology and design. For example, it uses the same diameter reactor pressure vessel as the ABWR and some of the same internals. The original SBWR vessel internals were increased to the ABWR vessel diameter. As a result, the annulus size was verified for adequate water volume and flow, margins to thermal hydraulic instability were maintained and other design limitations were evaluated. The ESBWR core was also increased in size by adding fuel assemblies to increase the power level. Fuel height was decreased to 3 metres in order to achieve the appropriate pressure drop, while the power density was set to 54 kW/litre. The core was increased from the 732 fuel assemblies in the SBWR to 1132 fuel assemblies in the ESBWR, resulting in a thermal power rating of 4500 MW.
Natural circulation occurs both within the reactor pressure vessel and also during a loss-of-coolant accident (LOCA) as the steam flows to the Passive Core Control System (PCCS) with condensate returning back to the gravity driven cooling system (GDCS) tanks and then to the reactor pressure vessel. These uses of natural circulation allow for the elimination of several systems, including recirculation pumps and associated piping, valves, motors and controllers, safety system pumps and safety diesel generators.

Natural circulation in the reactor pressure vessel (RPV) is established because of density differences between water in the vessel annulus and the steam water mixture inside the shroud and chimney. Natural circulation is achieved through an increase in vessel height and a decrease in active fuel height, relative to current plants. Natural circulation is enhanced by the shorter fuel height, addition of a chimney, an improved steam separator assembly and by opening the flow path between the downcomer and the lower plenum.

Valuable operating experience was gained from previously employed natural circulation BWR designs. Examples of plants using only natural circulation include the Humboldt Bay plant in California, USA and the Dodewaard plant in the Netherlands, which operated for 13 and 30 years respectively.

Today, large BWRs – those of 1000 MW-plus – can generate about 50 per cent of rated power in natural circulation mode. The operating conditions in this mode – power, flow, stability, steam quality, void fraction, void coefficient, power density and power distribution – are predicted by calculation models that were calibrated against operating plant data from LaSalle, Leibstadt, Forsmark, Confluentes, Nine Mile Point 2 and Peach Bottom 2.

The ESBWR uses proven natural circulation technology to operate a reactor with the size and performance characteristics customers need today at 100 per cent of rated power.

2.2 ESBWR SAFETY SYSTEMS

The ESBWR safety system design is extended to a higher power level by taking advantage of the modular design approach of the safety systems. The isolation condenser systems and the passive containment cooling system use simple heat exchangers and therefore any increase in power level requires only additional heat exchangers or tubes.

The safety systems in the ESBWR are passive and include an Automatic Depressurization System (ADS), a GDCS, an isolation condenser system (ICS) and a PCCS.

The ADS consists of ten safety relief valves (SRVs) mounted on top of the main steam lines that discharge steam to the suppression pool, and eight depressurization valves (DPVs) that discharge steam to the suppression condenser system (ICS) and a PCCS.

In the GDCS the makeup water flows under gravity into the vessel after the ADS depressurizes the reactor vessel. The GDCS pool capacity is primarily determined by containment geometrical considerations. The GDCS and ADS form the plant’s ECCS.

The ICS removes decay heat from the reactor following transient events involving reactor scram, including station blackout. The ICS consists of four independent high-pressure loops, each containing a heat exchanger that condenses steam on the tube side. The tubes are in a large pool, outside the containment. The system uses natural circulation to remove decay heat.

CLICK TO VIEW FIGURE 4:

ISOLATION CONDENSER SYSTEM

The PCCS removes heat from inside the containment following a LOCA. The system consists of six safety-related low-pressure loops. Each loop has a heat exchanger open to the containment, a condensate drain line and a vent discharge line submerged in the suppression pool. The six heat exchangers, similar in design to the isolation condensers, are located in cooling pools external to the containment. The PCCS limits containment pressure to less than 40 psig.

CLICK TO VIEW FIGURE 5:

ESBWR PASSIVE SAFETY FEATURES

2.3 ESBWR PLANT PERFORMANCE

Substantial enhancement of overall plant performance is achieved.
through the key design features previously described, along with the use of the latest fuel designs. Natural circulation significantly improves key performance parameters, while keeping others within the same range as those on forced circulation plants. In addition, certain design changes in the ESBWR allow an increase in power level from the SBWR, without a decrease in margins. The reason is that significant bundle natural circulation flow in the ESBWR is due to the unrestricted downcomer area and shortercore, tall chimney above the core, and improved low-pressure drop separator configuration. The ESBWR’s natural circulation flow is nearly comparable to that of forced circulation BWRs operating in extended operating domains.

A reactor is generally more stable with a lower power/flow ratio. The ESBWR power/flow ratio is comparable to that of operating BWRs, which have extended operating domains. This is because the power per bundle is lower for the ESBWR and the natural circulation flow is increased, as previously described.

A slower pressurization rate in the ESBWR is a result of the large steam volume in the chimney and the use of isolation condensers. Because of the slower pressurization rate and the use of isolation condensers there is adequate margin to prevent any safety relief valves from opening during anticipated operational occurrences. This is a significant improvement from currently operating BWRs.

Lower personnel dose levels are a result of improved system design, reduced maintenance requirements and reduced surveillance testing requirements due to the passive systems, especially those within containment.

The elimination of the reactor recirculation pumps and associated heat exchangers removes all maintenance on potentially contaminated reactor recirculation motors, valves and heat exchangers. The use of FMCRDs also reduces personnel dose significantly since only a few need to be inspected and maintained during each outage.

New system designs and pipe routings eliminate the need for most crud traps. The selection of materials to eliminate or minimize cobalt content, the increased use of stainless steel and state-of-the-art water chemistry practices has reduced piping and equipment radiation sources. Systems with the potential for radioactive contamination are designed for draining, flushing and decontaminating to reduce dose levels. The ESBWR also uses epoxype type wall and floor coverings, providing smooth surfaces that make decontamination easier and ensure that radiation levels are as low as reasonably achievable (ALARA) throughout the plant.

Reduced low-level waste production is a result of fewer ESBWR maintenance activities. Simplification and the elimination of numerous active systems result in less outage work, lower total worker dose and decreased low-level solid waste generation. The ESBWR solid waste management system segregates and packages the reduced levels of wet and dry radioactive solid waste for off-site shipment and burial. This segregation allows for efficient processing and minimizes the overall amount of solid waste requiring disposal.

The new design combines improvements in safety with design simplification and component standardization to produce a safer, more productive and more reliable nuclear power plant with lower projected construction costs than plants in operation today.

2.4 ESBWR OPERATIONS AND MAINTENANCE

With the goal of simplifying the utility’s burden of operation and maintenance (O&M) tasks, the design of every ESBWR electrical and mechanical systems, as well as the layout of equipment in the plant, was focused on improved O&M.

The reactor vessel in the core beltline region is made of forged rings rather than welded plates. This eliminates 30 per cent of the welds from the core beltline region, for which periodic in-service inspection is required.

The FMCRDs permit a number of simplifications. First, scram discharge piping and scram discharge volumes (SDVs) were eliminated since the hydraulic scram water is discharged into the reactor vessel. By supporting the drives directly from the core plate, shootout steel located below the reactor vessel to mitigate the rod ejection accident was eliminated. The number of hydraulic control units (HCU) s was reduced by connecting two drives to each HCU. The number of rods per gang was increased up to 26 rods, greatly improving reactor startup times. Finally, since there are no organic seals, only a few drives will be inspected per outage rather than the 30 specified in most current plants.

It was possible to significantly downsize ECCS equipment as a result of eliminating large vessel nozzles below the top of the core. Capacity requirements are sized based on operating requirements – transient response and shutdown cooling – rather than on the need for large reflood capability. Inside the reactor vessel, core spray spargers were eliminated since no postulated LOCA would lead to core uncover.

Lessons learned from operating experience were applied to the selection of ABWR and ESBWR materials. Stainless steel materials that qualified as resistant to intergranular stress corrosion cracking (IGSCC) were used. In areas of high neutron flux, materials were also specially selected for resistance to irradiation-assisted stress corrosion cracking (IASCC). Hydrogen water chemistry (HWC) is recommended for normal operation to further mitigate any potential for stress corrosion cracking.

The use of material producing radioactive cobalt was minimized. The condenser uses titanium tubing or corrosion resistant ferrite stainless steel tubing at seawater sites and stainless steel tubing for cooling tower sites. The use of stainless steel in applications that currently use carbon steel was expanded.

The ESBWR reactor building, including containment, was configured to simplify and reduce the O&M burden. The
containing itself is a reinforced concrete containment vessel (RCCV).

Within the containment itself, no equipment requires servicing during plant operation. The containment is significantly smaller than that of the preceding BWR/6. However, primarily due to the elimination of any recirculation system, there is actually more room to conduct maintenance operations. To simplify maintenance and surveillance during scheduled outages, permanently installed monorails and platform permit 360° access and both the upper and lower drywells have separate personnel and equipment hatches. To simplify FMCRD maintenance, a rotating platform is permanently installed in the lower drywell, and semi-automated equipment was specially designed to remove and install that equipment.

Controls and instrumentation were enhanced through incorporation of digital technologies with automated, self-diagnostic features. The use of multiplexing and fibre optic cable has eliminated hundreds of thousands of metres of cabling.

Within the safety systems, the adoption of a two-out-of-four trip logic and the fibre optic data links have significantly reduced the number of required nuclear boiler safety system related transmitters. In addition, a three-channel controller architecture was adopted for the primary process control systems to provide system failure tolerance and online repair capability.

The man-machine interface was significantly improved and simplified for the ESBWR using advanced technologies such as large, flat-panel displays, touch-screen CRTs and function-oriented keyboards. The number of alarm tiles was reduced by almost a factor of ten. Many operating processes and procedures are automated, with the control room operator performing a confirmatory function.

The plant features discussed above, while simplifying the operator’s burden, have an ancillary benefit of increased failure tolerance or reduced error rates, or both. Increased system redundancies will also permit online maintenance. Thus both forced outages and planned maintenance outages will be significantly reduced.

2.5 ESBWR TURBINE GENERATOR AND STEAM AND POWER CONVERSION SYSTEM

It is difficult to completely standardize the ESBWR plant design beyond the nuclear island. In addition to utility preferences in the steam and power conversion system, there are also site unique issues, such as the ultimate heat sink (UHS) location and temperature, which can play a significant role in the selected configuration. What follows, therefore, is an example configuration, showing one possible implementation. Changes in this part of the plant will not have any significant impact on the nuclear island design or operation.

2.5.1 STEAM AND POWER CONVERSION SYSTEM

The turbine building houses all equipment associated with the main turbine generator and other auxiliary equipment. The turbine employs a conventional regenerative cycle with condenser deaeration and condensate demineralization. The turbine-generator is equipped with an electrohydraulic control system and supervisory instruments to monitor performance. The electrical output of the turbine-generator is about 1600 MWe in the standard ESBWR design.

CLICK TO VIEW FIGURE 6: ESBWR STEAM TURBINE

The components of the steam and power conversion system are designed to produce electrical power using the steam generated by the reactor, condense the steam into water and return the water to the reactor as heated feedwater, with a major portion of its gaseous, dissolved and particulate impurities removed in order to satisfy the reactor water quality requirements.

Steam, generated in the reactor, is supplied to the high-pressure turbine and the steam rehetters. Steam leaving the high-pressure turbine passes through a combined moisture separator/reheater prior to entering the low-pressure turbines. The moisture separator drains, steam reheater drains and the drains from the two high-pressure feedwater heaters are pumped back to the reactor feedwater pump suction by the heater drain pumps. The low-pressure feedwater heater drains are cascaded to the condenser.

The main turbine is a 1500 rpm, tandem compound, six flow, reheat steam turbine. The turbine-generator is equipped with an electrohydraulic control system and supervisory instruments to monitor performance. The net electrical output of the turbine-generator is about 1520 MW.

Steam exhausted from the low-pressure turbines is condensed and deaerated in the condenser. The condensate pumps take suction from the condenser hotwell and deliver the condensate through the filters and demineralizers, gland steam condenser, steam jet air ejector condensers and offgas recombiner condensers to the condensate boost pumps. The condensate boost pumps deliver the feedwater through the low-pressure feedwater heaters to the reactor feed pumps. The reactor feed pumps discharge through the high-pressure feedwater heaters to the reactor.

CLICK TO VIEW FIGURE 7: ESBWR FLOW SCHEMATIC

3. SUMMARY

Reactor technology has advanced over the past 50 years, with improvements in safety, reliability and operability. Even so, the further advancement of the technology continues. Generation III+ products such as the ESBWR made significant targeted improvements on their predecessors. The ESBWR is a Generation III+ reactor design built on the ABWR design success. It expands the
use of passive safety systems, along with additional refinements in simplification and the use of natural circulation.

**CLICK TO VIEW FIGURE 8: ESBWR + GENERATION III**

The ESBWR reactor technology has been under extensive formal licensing review in the United States since 2005, now allowing the Final Safety Evaluation Report to be scheduled for issuance in January 2011. That body of work and the resulting design can now be directly applied in Europe because many of the technical challenges being raised across Europe have been solved in the ESBWR design. Additional European requirements are simultaneously being addressed in forums with European utility customers and their regulations.

The ESBWR is true Generation III+ technology that can provide European customers with a simplified, competitive cost-effective solution, offering full passive safety systems that do not require any operator action or AC power for at least 72 hours to safely shutdown.
REFERENCES

Generally, reference to the information described above can be found in multiple licence documents and publicly available papers. Key aspects can be found in the following:

1. ABWR – USNRC Design Control Document (DCD)
2. ESBWR – USNRC Design Control Document (DCD)

AUTHORS’ BIOGRAPHY

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A Reliable IP Telecommunications Network for the Remote Management of Substations

1. INTRODUCTION
REE is the transmission system operator (TSO) responsible for the operation and technical management of Spain's high-power transmission system. Its main mission is to guarantee the availability and security of the power supply and to provide a unified national power grid.

To fulfil its mission, REE has to manage and remotely control equipment in substations, so it has built a long-distance IP-based telecommunications network called SERVIP that provides some critical telecommunications services. The importance of this network's mission means it has to be as reliable as the power grid itself. The aim of this document is to describe the structure of this IP network, its evolution and its objectives.

2. MOTIVATION FOR AN IP NETWORK
Classical telecommunications services in the past century were established using the technology of switched circuits over analogue and digital serial lines. These services were critical, as in the case of those that were oriented towards control or electrical protection, but the speed of information on them was low. Sometimes ISDN architectures were employed to provide these services by creating a shared digital infrastructure for telecommunications.

Around two decades ago applications that require IP emerged in electrical installations. These were initially for the management of electrical equipment, with the later addition of needs such as video conferencing and video surveillance, which required long distance interconnections and a considerable increase in bandwidth. To satisfy these growing demands at REE, a new TCP/IP network named SERVIP was designed and deployed. The goal was to provide IP connectivity to all the new applications that required TCP/IP transport and to extend the network to all of the company's facilities, namely its electricity substations.

Today, new IP services are leading the trend in new deployments. REE has to deal with issues such as quality of service and throughput, which have been always taken for granted. An additional push is coming from multimedia services that have real-time requirements. With that idea in mind, a new network is now being conceived, with the final goal of leaving SERVIP only to convey low-speed critical services.

3. PHYSICAL INFRASTRUCTURE
The REE IP network was initially built over an SDH-based transmission network that uses a hierarchy of up to STM-64 (10 Gb/second). This transmission network is deployed over a wide area fibre network built and owned by REE. This fibre network is single mode and consists mainly of Optical Ground Wire (OPGW) cables. REE has about 30,000 km of optical fibres that extend to almost every REE substation in the power grid of mainland Spain.

Today, the SERVIP network comprises approximately 450 routers and 1500 switches, reaching roughly 500 high-power substations.
network must not have an impact on the performance of the overall system. Accordingly, an IP-based network in which reliability is its strong point has been developed.

The guidelines for the design of the architecture of this wide area IP network were inspired by the following principles:

1. The architecture has to closely reflect the underlying transmission network (SDH or fibre), which means that a wide area network link in the IP network must correspond, if possible, to a transmission link in the SDH layer. Any situation in which a failure in one transmission link could affect several links in the IP network must be avoided. Complex IP links that stretch over several transmission links could result in situations in which the failure in a single network element causes a cascade of failures in several elements in upper layers, some in unexpected ways.

2. Each substation has to be connected to at least two physical paths. This requirement is coherent with the N-1 UCTE Criterion. This design means a single failure will have no impact on services that are carried by the network. Every node in the network must have at least two independent routes to the rest of the network. If this is not possible, then the number of common links and elements for the different routes must be minimized.

3. Simple concentration points of different paths have to be avoided. Separate paths connected to a substation must not be connected to the rest of the network with the same equipment. This avoids the situation in which a single failure in a device produces a failure in a service.

4. Devices with excessive traffic load must be avoided. Accordingly, the REE network set a maximum number of wide area traffic interfaces for a device.

5. If needed, alternative technologies are to be used in order to diversify access to each substation. The main criterion is to use optical fibre as the first option for interconnection. If it is not possible to have at least two different physical routes over fibre, then other technologies could be used, such as radio links.

One of the critical issues was the establishment of the long-distance connections. From the point of view of transmission there are three possible approaches:

- Directly over the SDH network. If the SDH network is already deployed, there will be a cost optimization. However, the cost must be taken into account E1 ports for routers or cards for SDH multiplexers.
- Direct fibre ports with SFP technology mainly used in short-distance links, usually inside substations. In long-distance links one of the limitations is that with standard SFPs, the bigger hops being about 70 km. For longer links, special equipment must be used, which means extra costs.
- Ethernet over SDH, typically using generic framing procedure and virtual concatenation. With this option, performance is directly related to the transmission resources assigned. Its principal drawback is that resources are allocated permanently, even if they are not used. It is conceptually simple and could be seen as a gentle evolution of classical transmission networks toward IP.

REE has used all of these three options, although today the first is the most common.

**CLICK TO VIEW FIGURE 4: SERVIP CONNECTIONS.**

**5. DESIGN OF IP ROUTING**

Routing design accorded with the organization of the company, the number of users and applications, and the geographical distribution of facilities and operational areas.

A simple hierarchical structure has been established by using an interior Gateway Protocol (IGP), which handles routing within a single autonomous system. Examples are well known, for example RIP, EIGRP, OSPF and intermediate system to intermediate system. In this particular case, OSPF was the chosen solution. Because it is a well known protocol and has an impressive number of references in the industry.

A backbone and several subnets were designed while keeping the number of the subnetworks as low and similar in size as possible, all in accordance with OSPF architecture. One aspect of relevance here is the physical structure. If there are natural transmission rings, these can be grouped into a regional subnetwork.

Again, a set of basic rules were followed:

- Create a backbone, (Area 0), that includes the headquarters and important centres such as those for operation and maintenance.
- Create several non-backbone areas. These could be regional subnetworks and should be of similar size. It is advisable to follow the layout of the transmission network as far as possible.
- Connect previous subnets to the backbone with at least one level of redundancy.

**6. SERVICES AND LOGICAL DESIGN**

A VLAN approach has been used inside each substation. Each critical and differentiated service, such as the management of protection relays or control, and measurements of RTU, was assigned to a VLAN. In this way all the equipment in a substation assigned to the same service were grouped in terms of traffic and isolated from the rest of the network. So a management laptop for RTU configuration is not able to access protection equipment.
Typical services assigned to VLAN are:

- RTU management
- Management of protection relays
- Remote management of telecommunications equipment
- Supervision of the DC power supply system
- Interconnection of point-to-point devices

One of the main concerns when establishing an IP network is dimensioning the address space so that it can fit into the company structure, scale well and provide an address for every host in the network and optimal use. In order to define VLANs of different sizes inside the network, an approach can be employed that uses a variable length mask. It is necessary to keep in mind that VLAN definition will impact the structure of the whole network. Its repercussions will particularly be felt in areas such as security controls.

7. EQUIPMENT AND BUILDING BLOCKS

Routers are the basic elements in an IP network because they are the optimal way of connecting several segments. In SERVIP, routers play a central role. In almost every substation there is a router whose mission is to convey the information to long-distance links by means of IGP routing. Inside the substation is a structure of interconnected switches that collects traffic from different services in different premises. These are linked by a multimode optical fibre local area network. Each connection between switches is duplicated to ensure redundancy.

8. SECURITY

Due to its strategic nature and its security implications, SERVIP has been isolated from the outside world, both physically and logically. Only REE-owned physical infrastructure has been used. This avoids interdependencies with third parties whose commercial goals could differ from those of the TSO.

Furthermore access to SERVIP is only possible from specific dedicated computers called TASS – the Spanish acronym for service secure access terminal – with enhanced implemented security. Another important security measure is the prevention of physical access to elements in the network. All the points in SERVIP are inside REE installations and under security to prevent access by intruders.

9. RESILIENCE

It is easy to see that the main objective of the SERVIP network is to make the operation of the power grid reliable and to make it resilient. The equipment, protocols and design employed in this network have been conceived for dealing with a single failure and with simultaneous combinations of failures. As an example, during a recent storm in northeast Spain, the telecommunications network proved to be as reliable as the power network. SERVIP gave the power control centre in REE headquarters the management and supervisory means to act efficiently to recover power efficiency.

10. EVOLUTION

Today the SERVIP network provides the infrastructure for developing and implementing any critical application that could be based on IP. Future developments are expected to come in the form of implementation of the IEC 61850 protocol and through Smart Grids.
AUTHORS’ BIOGRAPHIES

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Towards a Standards-compliant Smart Grid: Semantic Web Technologies and Interoperability, Security and SOA

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ABSTRACT

The utility domain is facing new problems in transmission and distribution systems. An improved reliability and efficiency of overall systems is one of the main goals of the Smart Grid. The Smart Grid includes many stakeholders and is a system of high complexity, but should facilitate a transition of the whole industry. The Smart Grid also brings up new security and safety issues, and it has to be an enabler for a consensus on standards and their development and support.

Technically there are many challenges in terms of smart equipment, communication systems, data management, cyber security, information and data privacy, and new software applications. In our research we emphasize semantic web technologies as an appropriate solution to meet these challenges. In this paper, we present three cases of the use of these technologies when it comes to interoperability, security and communication.

In the case concerning interoperability, we model the IEC TC 57 standards as ontologies and develop ontology alignments to harmonize the data quality codes according to IEC 62361.

In the case concerning security, we deal with creating an overall security-management ontology by connecting three ontology parts: domain-specific data models, non-functional requirements and security concepts. The overall ontology provides important information which can enable users to gain additional information by allowing search and reasoning facilities.

In the case concerning communication, it is essential to have common semantics and syntax provided by a domain-specific ontology. Thus the common information model (CIM, IEC 61970/61968) should be the basis for all communication processes on the different layers using semantic web services. Focusing on the power infrastructure communication, the OPC UA (IEC 62541) is the right choice.

1. ICT CHALLENGES FOR SMART GRIDS

Information and control technology (ICT) plays a key role in the scope of the so-called Smart Grid. ICT and automation technologies have to be properly combined and must work alongside each other to build the Smart Grid. The Smart Grid is at the very end of a process of transition from the current classic grid via a grid that is more or less smart. The overall issue is to combine existing, modern ICT technologies with proper automation solutions to enable us to make the grid smart.

In this paper we focus on the combination of established IEC TC 57 standards from the so-called seamless integration architecture (SIA) alongside W3C-based semantic web standards based on the established semantic web stack.

We also provide an overview of the IEC 62357 SIA, which is considered to be the core standards framework for the Smart Grid of the future by most renowned experts and organizations. These include the International Electrotechnical Commission (IEC), the National Institute of Standards and Technology (NIST) and the Deutsche Kommission Elektrotechnik (DKE). Then we provide a short introduction to the W3C semantic web stack, sometimes mistakenly called called Web 2.0 techniques.

Following this we cover three ‘use cases’. The first discusses the semantic-based integration of quality meta data annotated at field data which has to be converted from one standard to another. The second use case deals with ontology-based information security management for the energy domain. The last case focuses on semantic-based service-oriented architecture (SOA) for the automation layer. We conclude by asking whether semantic web technologies are appropriate for the chosen cases.
Mathias Undar

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Towards a standard compliant Smart Grid through Semantic Web Technologies concerning interoperability, security and SOA
2. TC 57, SEAMLESS INTEGRATION ARCHITECTURE

The standards to be used in the Smart Grid of the future mean different technologies have to be combined. The IEC TC 57 has developed a framework to build a layered approach for standards covering the whole vertical and horizontal function and communications chain in an electricity utility (see Figure 1). On the top layer, we deal with market communications and the IEC 62325 standard, which uses ebXML-based payloads utilizing the CIM for UN/CEFACT-compliant processes. The basic data model can be serialized using XML to make SOA-based payload exchange between systems possible. Furthermore, an RDF-based serialization called CIM/XML is used to model large power grid topologies and exchange them. This is a true semantic web application which is both scalable and industry proven.

The CIM can be extended with its own semantics if objects are missing and bridges to other domains are possible, for example multi-utility-based approaches. This layer of the SIA is near enough state-of-the-art IT technology for modern enterprise systems used in business-to-business communications. Below this begins the automation layer, which has to be integrated with the IT layer. The IEC 61850 family is the most important standard in this layer. It is being used to communicate with, configure and properly operate substations, distributed generation, smart meters and wind power plants. The IEC 61850 replaces the old datapoint-oriented standards with a new object-oriented virtualization and abstraction approach which fits better with the IT world than the previously used IEC 60870 standards. The IEC 62351 series of standards provides security measures that are used within the whole IEC 62357 SIA. Apart from this architecture, other standards-developing organisations have to be taken into account when dealing with the Smart Grid. A short overview of the most important ones is given in Figure 2.

3. SEMANTIC WEB TECHNOLOGIES

The vision was to create better web data which would incorporate semantics and less mark-up, making the web accessible to users through their browser and also providing proper meta data and context for automatic reasoning and interpretation. Based on the core standards for document exchange, the uniform resource identifier (URI) and Unicode, the first important layer is the Extensible Markup Language (XML) and the XML schema layer, which is extended by the namespace concept. Namespaces can be used to make extensions and to combine different XML-based vocabularies. It is on XML that the real semantic web stack starts. The resource description framework (RDF) is based on triples using XML, which reflects facts given by subject, predicate and object, just like a sentence in a spoken language. Furthermore special predefined XML tags provide semantics to build a proper vocabulary which can be interpreted by reasoners. This is the basis for ontological vocabularies which provide more formal semantics than RDF does. Logic inference can be used at this level to find out new knowledge from existing facts. The final levels, proof and trust are little used. They are not state-of-the-art.

The CIM is provided as an ontology for the electricity utility domain using RDF for topologies and Web Ontology Language (OWL) for the basic domain ontology. Therefore it is possible to use proper semantic web technologies when working with the CIM and to further automate system functions and EMS and DMS applications at primary and secondary IT level.

4. APPLICATION OF SIA AND SEMANTIC WEB TECHNOLOGIES

We now present different use cases to show how semantic web technologies can help to make working with the SIA more efficient.

4.1 ENSURING DATA QUALITY FROM FIELD DEVICES

The electrical power supply system requires communication between different types of substations and field equipment to exchange data for the operation of the electrical network. The TC 57 framework (IEC2003) specifies the communication standard for this. One problem with the communication is the use of different standards.
Figure 4 shows an example of possible communication paths in an electrical power supply network, including proposed standards. Quality codes are placed within this communication to evaluate the data. Each standard defines a different quality code, which is part of the problem. Because established standards are difficult to change, the only way to transmit the data is to convert them between the standards.

CLICK TO VIEW FIGURE 4: COMMUNICATION PATHS FROM FIELD DEVICES TO CONTROL CENTRE

Standard IEC 62361 [IEC2007a] was created to harmonize the conversion of quality codes during transmission. This standard is only available in document form without an electrical data model. That means it is not applicable for use by converters related to any system interface. For this our approach uses formal mappings. This allows an implementation of these mappings as an artifact within a development process.

The basic concept of our approach is to use an ontology to model the relationships between the different data models and concepts of various standards. To achieve a harmonization of the quality codes, these quality codes are modelled in OWL to develop an ontology for each standard mentioned in IEC 62361. In the next step the harmonization takes place using mappings. These mappings connect the different standard ontologies and serve as mediators (see Figure 5).

CLICK TO VIEW FIGURE 5: CONCEPT FOR THE MEDIATOR ONTOLOGY IN USE

Figure 6 shows an explicit mapping procedure of the attribute validity. In accordance with the IEC 61850 standard the attribute can take the type ‘invalid’, whereas the IEC 61970 standard allows the type ‘bad’ with the same meaning. These two types must now be brought into a relationship through the use of the OWL command equivalentClass.

CLICK TO VIEW FIGURE 6: MAPPING OF THE ATTRIBUTE VALIDITY BETWEEN THE TWO STANDARDS IEC 61850 AND IEC 61970

Our approach includes two ways to create these mappings:

- Manually modelling the IEC 62631 as an ontology
- Automatic generation of mediator ontologies with the help of a so-called ontology matcher, such as the COMA++ framework.

The results of the evaluation of the two procedures show that the manual modeling provides a better quality of mapping.

A prototype was programmed which can be used in a scenario to reflect a typical communication chain from field devices to the control centre through different standards.

This prototype is implemented as a Java web service. It offers the possibility of inputting quality codes of a specified standard in bit string format and the desired communication chain in terms of the used standards to gain the converted bit string quality code of the target standard. In addition the information loss of data which takes places during the conversion will be delivered.

During the process, the prototype uses the designed ontologies, which have been derived out of the IEC 626731 standard. Theses ontologies are also meant to be used in other project contexts.

4.2 ONTOLOGY-BASED INFORMATION SECURITY MANAGEMENT FOR THE ENERGY DOMAIN

There are different requirements for information objects in the energy domain. Some non-functional requirements originate from laws, standards or domain-specific requirements such as that for high availability [NIS2010]. For example, in Germany – as in most other European countries – commercially sensitive data such as customer load have a security requirement, defined within the law [EVG2005].

This law usually enforces companies to treat commercially sensitive data as confidential. As such, confidentiality can be called a ‘security goal’ for this type of data. The appropriate realisation of security mechanisms in a specific context for a corresponding security goal is important for cost-benefit optimization. Whether or not the confidentiality of an object is under threat – and therefore an implementation of a security mechanism is necessary – depends on the context or system in which the specific object appears. Therefore subjects, contexts, processes or concurring requirements of a specific object are essential information needed to define security requirements.

In this paper’s approach, we are proposing an ontology for defining this essential information and for modelling the connections. Machine-readable standards and security policies are used to introduce a holistic ontology-based security management concept for the energy domain. Existing knowledge bases such as data models from CIM and security policies are transformed into ontologies and used within the holistic concept.

An overall ontology integrates different existing ontologies and standards, and connects them with each other. Consequently a re-use of existing knowledge and existing ontologies is fostered within our proposed approach. Ontology alignment can be used for integrating security requirements in the semantic net of enterprise information objects. There are many security ontologies to describe concepts such as threats and countermeasures in the literature. [BIV2008] gives an overview of different security ontologies.
In addition to integrated security ontologies, the overall ontology contains energy-specific possibilities to adequately represent the functional and non-functional requirements and security concepts of the energy sector.

As such the resulting ontology consists of the three parts shown in Figure 7: domain-specific data models (in the upper right green box), non-functional requirements (in the left grey box) and security concepts (in the blue box below).

To allow good visualization of this, Figure 7 shows only a few of the main concepts of the overall ontology and has just a few hints of connections. A central point is the concept ‘object’. This is a (meta) model for (information) objects of the energy domain. Security requirements or domain-specific requirements are defined for each instance of object or object group/type.

**CLICK TO VIEW FIGURE 7: MAIN CONCEPTS OF THE ENERTRUST ONTOLOGY**

Figure 7 also shows some sub-concepts of objects such as IEC 61970 customer data models as examples in the box. These object instances are used by different subjects and are in different processes. Objects occur in a specific context, even though vulnerabilities appear in a specific system context. Security goal, on the other hand, is also a concept of the overall security ontology. This concept has some subclasses such as confidentiality.

The eavesdropping type of attack is connected to the concept of confidentiality. It is the corresponding attack for that security goal. These relationships are modelled in the ontology so that an integrated net of information connections occurs. Furthermore security patterns for security mechanisms and security metrics for security patterns are mentioned. Ontologies are extensible so that new concepts or patterns can be integrated (Open World Assumption).

After the ontology is instanced it holds requirements for objects and security goals. This is a kind of machine-interpretable security policy. Moreover it may include security patterns, metrics and possible attacks for a security goal and context. Therefore the ontology can provide possible solutions and metrics to measure the efficiency of the solution. In addition to this an ‘attack tree’ can be generated to optimize the solution via penetration testing.

The overall ontology provides important information, which can allow users to gain additional information by allowing search and reasoning facilities and by making knowledge accessible and interpretable by IT systems. The current version of our ontology has over 400 concepts.

It is defined and implemented in the Web ontology language OWL DL [W3C2004]. To easily access information in this highly connected knowledge base and in order to get a quick overview of concepts of interest today, semantic query languages like SPARQL can be used [W3C2008].

The following example statement lists all objects from the overall ontology with corresponding security goal ‘confidentiality’ and the processes in which the objects are used.

**CLICK TO VIEW EXAMPLE STATEMENT**

Managing and accessing knowledge as in our ontology can be time consuming. Here Reasoner, like Pellet, can help [W3C2010]. This Reasoner produces a generation of new knowledge by making conclusions and inferences.

If the Reasoner knows that commercially sensitive data have to be treated confidentially because of restrictions defined within the ontology and originated from the law, it can draw the conclusion that object A, which is from a commercially sensitive type, has the security goal ‘confidentiality’. Moreover it can conclude that object A should be protected via an encryption algorithm as a security mechanism because of the security goal ‘confidentiality’.

The energy domain has a host of unique requirements. For example, high availability of IT systems and information is crucial in the energy domain and may sometimes even lead to realtime requirements. As such, security conditions may be in conflict with domain-specific requirements. For example, the installation of a virus scanner as a security enhancement can have negative impacts on the requirement for high availability or response time [GRE2006].

The ontology presented in this paper is capable of modeling those conflicts and determining them during the design stage. Moreover the ontology can supply information about which regulation is connected with an information object. This allows the expression of how a specific information object needs to be secured in order to be in accordance with the law. This can be done via reasoning.

**4.3 SEMANTIC-BASED SOA FOR THE AUTOMATION LAYER**

Monitoring, protection and automatic optimization of the operations of its interconnected elements are key issues of this process. Those elements include central and distributed generation through the high-voltage network and distribution system, industrial users and building automation systems, energy storage installations and end-use consumers and their thermostats, electricity vehicles, appliances and other household devices [vDo2009].

Compared with that vision, the Central European vision has a stronger focus on distributed energy resources (DER) and does not focus primarily on the grid itself but on all involved systems and components. The different stakeholder groups – consumers, utilities and society – can expect benefit in economies, safety and cyber security, energy efficiency, and the environment or conservation [vDo2009].

Many challenges will result from this transformation process. One of those challenges is concerned with communication, or data exchange. Both the communication between stakeholders and the
communication within a single stakeholder have to be taken into account.

Related to the first case, several studies and reports [LiJ2009], [vOx2009] and [Gue2009] argue for the use of standards, mainly from the IEC and similar organizations. We follow this advice and use the IEC 61968/61970 series of standards [IEC2003b, IEC2008a], which were unanimously declared core standards, as the syntactic and semantic basis for an SOA that can cope with layer-comprehensive data exchange between different stakeholders.

This series of standards defines the CIM, which is a widespread domain-specific data model, and could be seen as a domain ontology for the utility domain [HKR2009]. Also the IEC 62541 (OPC Unified Architecture, UA) [IEC2008b] and the concept of semantic Web services are part of the developed SOA [RUA2010]. We take the state-of-the-art Generic Interface Definition (GID) Application Programming Interface (API) of the CIM and extend it by using the OPC UA. The UA communication is now improved by semantic web services. Figure 8 shows the resulting architecture. To cope with the impending novel requirements of the energy sector a platform-independent approach as provided by the platform-independent CIM and OPC UA is indispensable.

CLICK TO VIEW FIGURE 8:
COMBINING CIM AND OPC UA

New services are needed to provide processes that combine old and new systems. Furthermore legal unbundling and distributed generation creates new requirements for ICT in Smart Grids. Those requirements can be covered by web service based SOA. At this point our approach enters the ICT infrastructure. However, the approach, even though highly standardized, lacks some important features. CIM and UA cover syntax and semantics but the semantics is not taken into account in terms of discovering appropriate services from various systems or components.

The concept of semantic web services is the way to solve this problem. An OPC UA-based server can provide services which are annotated with meta data concerning attributes such as costs, quality of service (QoS) and availability. For example, a weather forecast service is needed to generate a load forecast. In this case various service providers provide apparently appropriate weather forecast services.

Our approach helps to find the most adequate service by considering functional and nonfunctional requirements. Combining the CIM with the OPC UA means modelling the CIM in an OPC UA server address space. CIM standardizes what kind of data has to be exchanged, the UA standardizes how they can be exchanged. Hence the CIM – a domain specific information model – is the data model that should be set on top of the abstract OPC UA model.

Accordingly the UA address space [MIL2009] is the target for mapping with the CIM. The CIM is maintained in a UML model and IEC 62541-3 includes a UML meta model for the UA data model. UML is the basis for the mapping. Therefore the following UA objects are taken into account:

- BaseNode
- Reference and ReferenceType
- Predefined ReferenceTypes
- Attributes
- Object and ObjectType
- Variable and VariableType
- Method
- EventNotifier
- DataType
- View

In our implementation the abstract CIM UML classes are mapped to the abstract OPC ObjectTypes. Instances of the abstract CIM classes are mapped to OPC UA Objects. Among these general mapping decisions some basic design decisions, concerning special cases, have to be made. For instance, CIM attributes can either be mapped to OPC UA Properties or OPC UA Data Variables.

Mapping CIM associations is not easy because their cardinalities have to be considered. They can be mapped to OPC UA References but OPC UA ModellingRules must also be created to cope with the cardinalities. So far, the mapping is server independent but the next modelling decisions depend on the server’s structure. OPC UA Methods are a powerful means to implement various functionalities to provide Smart Grid functions. The OPC UA Views concept is used to grant different users or user groups access only to those parts that are relevant to them.

A second use case for this concept also exists. The CIM is a very large and complex model that is rarely used as a whole. Profiles are defined, including only essential classes, attributes and associations, with defined cardinalities. Those profiles can be modelled by OPC UA Views.

Finally, the modeled OPC UA address space based on the CIM provides a good approach to realize an SOA on the Smart Grid automation layer, covering both the important issues of being compliant with standards, as well as finding the right services by using semantic web services.

CONCLUSION

Semantic web technologies are an appropriate instrument to provide a basis for the conversion of different standards because we could evaluate from the view of the integration of quality codes. The necessary ontologies could easily be formalized out of the
standards. Mappings are adequately described but today a domain expert is still necessary to integrate undocumented knowledge in the specific ontologies.

The Enertrust ontology enables information security management for the energy domain. Therefore ontologies are used for integrating existing knowledge from the energy and the security domain. To manage the huge size of highly connected concepts, semantic query languages can help to provide a quick overview of the requirements, security mechanisms, etc. In addition reasoning and rules can be used to conclude new knowledge like the need for implementing a security mechanism.

A communication architecture for the automation layer based on the OPC UA, combined with the CIM and using semantic web services, provides an appropriate means to integrate systems and components seamlessly into the overall Smart Grid. The resulting semantic-based SOA helps to find appropriate services by annotated meta data.

A mostly automated discovery and execution of services could be realized. By specifying the three use cases, we have shown that our promising approach to a standards-compliant Smart Grid based on semantic web technologies is applicable.
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The Impact of Grid Dynamics on Low Voltage Ride Through Capabilities of Generators

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ABSTRACT
The increasing amount of local electricity generation sources is affecting the operating methodology of electrical transmission and distribution grids. Until today, policies have been to immediately disconnect local generators when extreme disturbances in frequency and voltage occur. However, the presence of so much local generation capacity decreases the relative amount of central power so that switching off local capacity might introduce grid-support challenges. This has spurred grid companies worldwide to issue revised regulations for local and central generation with respect to their ability to support the electrical grid when disturbances occur. The ability to support the grid during deep voltage transients depends on the one hand on the technical features and load of the connected generator and on the other hand on the dynamic characteristics of the electrical grid to which it is connected.

This paper will use computer-simulated examples to show what the impact is of different grid characteristics.

1. INTRODUCTION
Until recently network operators in many countries mandated that local generation should quickly disconnect from the network when severe network disturbances occur. However, market deregulation, lessons learnt from past incidents and the increasing penetration of distributed generation have spurred changes to this practice.

To help prevent a potentially larger impact on the system, distributed generator units are now mostly required to stay connected when severe disturbances occur so that they can support the electrical network during and after a disturbance.

As such, this change of practice can be viewed as a natural result of the evolution of the modern electrical grid, where distributed generation plays a part in balancing. Cogeneration units driven by reciprocating engine sets, for example, suit this task well.

Reciprocating engine sets with synchronous generators can provide excellent services to the modern electrical grid, especially with the increasing penetration of renewable and distributed generation.

Generation based on reciprocating engines offers inherent balancing benefits. These are fast start-up and rapid loading times, good load following capabilities, and reactive power support. These features, combined with electrical efficiency above 44 per cent in electricity generation and fuel efficiency of over 85 per cent in combined heat and power applications suit them well to support electrical grids, dynamically and economically, in an environmentally sustainable way.

The rapid and efficient addition of generation capacity is also beneficial when it comes to covering peak or intermediate loading, hourly, daily or seasonally. By efficiently producing power close to where it is consumed, the need for costly infrastructure investments can further be reduced.

1.1 NETWORK DISTURBANCES
Faults and disturbances in the electrical transmission and distribution system can never be completely avoided. Short circuits and earth faults will occur regardless of the efforts of system operators. For a short time before the fault is cleared, it may have a severe impact on the local voltage.

The new requirement to stay connected when a severe disturbance occurs is typically issued via a simplified form of time-voltage fault ride-through (FRT) curve, also called the low-voltage ride-through (LVRT) curve. At the interconnection point to the grid, generators must tolerate a voltage above or equal to the FRT curve without losing synchronism.

CLICK TO VIEW FIGURE 1: EXAMPLES OF FAULT RIDE-THROUGH REQUIREMENTS
Today the requirements differ substantially depending on the issuing transmission system operator (TSO). Differences exist even between TSOs that are synchronistically connected, as is the case in Europe. The ability of the generating set to remain in synchronism during and after a short circuit depends on its construction, loading and control, the condition of the grid to which it is connected and the specific rules for interconnection.

2. FACTORS AFFECTING FAULT RIDE-THROUGH

Generally speaking the factors affecting fault ride-through that can be said to be attributable to the electrical system, interconnection rules and generating set are given in Table 1.

### CLICK TO VIEW TABLE 1:
FACTORS IN FAULT RIDE-THROUGH EVALUATION.

2.1 TRANSIENT STABILITY

The electrical system can be said to be stable when the synchronous machines connected to it operate in synchronism and in parallel with each other, and there is a balance between the demand and production of both active (P) and reactive (Q) power.

Transient stability is the ability of a power system to maintain synchronism when subjected to a severe disturbance. The disturbance can be in the form of sudden load changes, faults within the transmission and distribution system, and loss of generation.

2.1.1 PRESENTATION OF THE CIRCUIT AND SIMULATION METHOD

In order to demonstrate how different network conditions during a disturbance affect a local generator’s ability to stay in synchronism, this paper will study an 8.7 MVA unit connected through a power transformer to the high-voltage grid. Local loads are connected at the 0.415 kV and 132 kV networks. The 20 kV network in turn is connected through a 30 MVA transformer to an ungrounded 20 kV medium-voltage network. The 20 kV network is synchronistically connected to the 3-phase short circuit was established at the 20 kV bus and the system response was recorded.

2.1.2 REFERENCE SIMULATION

The first simulation was run to establish the reference conditions for the voltage behaviour and system dynamics of a local generator using Matlab®. The generating unit is modelled with its associated components in Matlab.

2.1.2.1 BASIC CIRCUIT DYNAMICS WITH LOCAL GENERATION

The local generator is initially operating synchronously at a grid reference voltage (V). The voltage behaviour and system dynamics of a local generator during a short circuit in the network. A 150 ms bolted 3-phase short circuit was established at the 20 kV bus and the system response was recorded.

In this paper the load angle (δ) is defined as the integral of the difference between the generator rotor angular speed (ω) and the synchronous reference speed of the system (ωs) in electrical degrees according to Equation 1.

\[
\text{Load angle equation: } \delta = \omega - \omega_s + \int (\omega - \omega_s) dt \tag{1}
\]

Neglecting losses, at a constant mechanical input power (\(P_m\)) equal to the power required to drive the generator at a given electrical output power (\(P_o\)), acceleration power (\(P_a\)) is zero as (\(\omega = \omega_s\)), according to Equation 2. The speed of the generator is equal to the synchronous speed (\(\omega_s\)) of the system.

\[
\text{Equation of motion: } \frac{2H}{\omega_s^2} \frac{d^2 \delta}{dt^2} - (P_o - P_a) \sin(\delta) = P_a \tag{2}
\]

### CLICK TO VIEW FIGURE 3:
BASIC CIRCUIT RESPONSE OF A LOCAL GENERATOR TO A BOLTED 3-PHASE SHORT CIRCUIT AT THE 20 KV BUSBAR

When a 3-phase bolted fault occurs (at t = 2.11 seconds) the voltage at the fault point will go to zero and no electrical power can be transferred to the receiving network (\(P_o = 0\)), according to Equation 3.

\[
\text{Electrical power equation: } P_o = \frac{E^2 V}{X} \sin(\delta) \tag{3}
\]

While \(P_o = 0\) the input power (\(P_m\)) is still unchanged as the generating set cannot reduce load instantly [1]. The difference in power (\(P_m - P_o\)) will lead to an angular acceleration of the rotor with respect to the synchronous reference speed, according to the basic dynamic rule of Equation (2). The acceleration of the rotor will advance the rotor load angle (δ) further with respect to (Δδ) until the fault is cleared. When the fault is cleared (at t = 2.11.15 seconds) the electrical power (\(P_o\)) will abruptly increase to a value corresponding to the angle at clearing (\(\delta_c = 70^\circ\)).
The electrical power ($P_a$) now exceeds the mechanical power ($P_m$), and the accelerating power ($P_a$) is negative, causing the rotor to decelerate. The rotor speed is still above the synchronous reference speed and thus the rotor angle will continue to advance to the maximum angle ($\theta_a = 92^\circ$), where the speed will be synchronous. However, since the accelerating power is negative the rotor angle will continue towards a minimum load angle ($\theta_a = -1^\circ$), where the speed will again be synchronous, as $P_m > P_a$ here, re-acceleration has occurred. If the system were uncontrolled and without damping and loss, the rotor would continue to swing indefinitely between ($\theta_k$) and ($\theta_k$). In a stable real system, and as seen here, the swings will dampen out after a time because of system damping, losses and engine/generator control actions.

The simulation also shows that during the fault, both the active and reactive power output of the generator is highly oscillatory in nature and that there is an active and reactive power swing in the transient condition immediately following fault clearing. The amplitude and duration depends on network conditions, fault severity and generating set inertia and control.

For a 3-phase fault at the 20 kV, bus the voltage also collapsed at the downstream 0.415 kV bus but only a slight dip was noticeable in the 132 kV system.

3. LVRT PERFORMANCE WITH DIFFERENT NETWORK PARAMETERS

3.1 FAULT CLEARANCE TIME

In order to establish the effect of fault clearing time on the FRT capability, a fault was applied at the 20 kV bus. The fault clearance time was increased stepwise from 100 ms until the critical fault time $t_{cr}$ was reached and the generator fell out of step, (in this case at $t_{cr} = 200$ ms).

3.2 FAULT TYPE

In order to establish the effect of the fault type on FRT capability, the same network was subjected to four different faults at the 20 kV bus: 1-phase to ground, 2-phase short circuit, 3-phase short circuit and an evolving fault going from a single-phase fault to a full 3-phase fault. The fault clearance time was set to 150 ms.

This theory, however, contains several simplifying assumptions and computer simulations are therefore usually needed [2].

Reasonable fault clearing times are critical for stability, as can be seen here. It can be argued that the demand for overly long clearance times, in excess of 150 ms, is too stringent and does not correlate with the typical prescribed primary fault clearance time of 80–150 ms in EHV and HV systems, nor with the typical voltage dip durations. Studies have shown that more than 75 per cent of faults in MV and HV systems are intermittent in nature or have a duration of under 200 ms [3, 4].

3.3 ABSOLUTE LEVEL OF THE VOLTAGE DIP

For a 3-phase fault at the 20 kV, bus the voltage also collapsed at the downstream 0.415 kV bus but only a slight dip was noticeable in the 132 kV system.

The effect can easily be seen with the help of classic theory simplification. The area that represents accelerating $A_1 = \frac{1}{2} (P_m - P_e) \Delta \theta$ energy and the area representing decelerating energy $A_2 = \frac{1}{2} (P_e - P_m) \Delta \theta$ must be equal in order for the system to be stable. Each increase in the angle at clearing ($\theta_k$) will increase the area representing accelerating energy ($A_1$) and decrease the area representing decelerating energy ($A_2$), the other factors remain unchanged until ($A_1 > A_2$) and the unit loses synchronism.

This model, however, contains several simplifying assumptions and computer simulations are therefore usually needed [2].

Reasonable fault clearing times are critical for stability, as can be seen here. It can be argued that the demand for overly long clearance times, in excess of 150 ms, is too stringent and does not correlate with the typical prescribed primary fault clearance time of 80–150 ms in EHV and HV systems, nor with the typical voltage dip durations. Studies have shown that more than 75 per cent of faults in MV and HV systems are intermittent in nature or have a duration of under 200 ms [3, 4].

3.2 FAULT TYPE

In order to establish the effect of the fault type on FRT capability, the same network was subjected to four different faults at the 20 kV bus: 1-phase to ground, 2-phase short circuit, 3-phase short circuit and an evolving fault going from a single-phase fault to a full 3-phase fault. The fault clearance time was set to 150 ms.

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3.3 ABSOLUTE LEVEL OF THE VOLTAGE DIP

For a 3-phase fault at the 20 kV, bus the voltage also collapsed at the downstream 0.415 kV bus but only a slight dip was noticeable in the 132 kV system.

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The simulation also shows that during the fault, both the active and reactive power output of the generator is highly oscillatory in nature and that there is an active and reactive power swing in the transient condition immediately following fault clearing. The amplitude and duration depends on network conditions, fault severity and generating set inertia and control.

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The electrical power ($P_a$) now exceeds the mechanical power ($P_m$), and the accelerating power ($P_a$) is negative, causing the rotor to decelerate. The rotor speed is still above the synchronous reference speed and thus the rotor angle will continue to advance to the maximum angle ($\theta_a = 92^\circ$), where the speed will be synchronous. However, since the accelerating power is negative the rotor angle will continue towards a minimum load angle ($\theta_a = -1^\circ$), where the speed will again be synchronous, as $P_m > P_a$ here, re-acceleration has occurred. If the system were uncontrolled and without damping and loss, the rotor would continue to swing indefinitely between ($\theta_k$) and ($\theta_k$). In a stable real system, and as seen here, the swings will dampen out after a time because of system damping, losses and engine/generator control actions.

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We can see from the plot in Figure 5 that in this simulation the instant 3-phase fault was the most severe, followed by the evolving 3-phase fault. For a 2-phase fault some power can still be transmitted into the network, thus limiting the speed and angle deviation. As the 20 kV system is ungrounded the generating unit did not see the single line-to-ground fault as a fault as the phase-to-phase voltages remain intact.

Depending on the network connection, unbalanced faults can propagate differently in networks due to differences in grounding practices and transformer connections, where 3-phase faults propagate through the transformers without changes [9].

It is generally acknowledged that the 3-phase fault is the most severe type of fault and is typically the benchmark in stability studies, which was also seen here. Fortunately 3-phase faults are very rare in the transmission and distribution system. It is recognized that only 2.5 per cent of faults involve all three phases and the most common fault is a 1-phase to ground, representing 70–85 per cent of the faults [9].

3.3 ABSOLUTE LEVEL OF THE VOLTAGE DIP

In order to evaluate the impact of the residual voltage in the voltage dip on the FRT capability, an impedance was placed between the 20 kV and the 0.415 kV bus to limit the depth of the dip. The fault clearance time was chosen to be 150 ms. The response of the set was monitored for 0 per cent residual voltage at the 20 kV bus, 20 per cent, 40 per cent and 70 per cent.
3.3 FAULT CLEARING TIMES

A bolted fault (zero impedance) is a very rare occurrence. In the majority of cases as reported in [3] and [4] and in the 2010 CIGRE study on voltage dip immunity, the voltage does not actually go down to zero at the measured points. In most of the dips, the residual voltage is higher than 40 per cent of the nominal voltage. The report from the Italian MV network showed that only 12 per cent of the average number of dips per point per year were below 40 per cent and only 0.2 per cent reached zero voltage [3]. A number of factors affect the final residual voltage at any point in the network: the resistance of the fault, the electrical distance from the fault point, the transformer connections and the topology and strength of the grid. For the modern electrical grid we must also add another factor: the presence of local generation. One can thus argue that it is unlikely that a large number of distributed local generators would see a voltage dip down to zero. This is especially the case in MV systems, which would spur a more widespread disconnection of local generation. In the MV distribution, where the fault frequency is higher, a fault in a distribution system fed from one substation will most probably not be seen as a severe fault in the HV/EHV system nor in an MV network fed from a neighbouring substation due to the impedances involved. The voltage plot in Figure 3 also shows this. The dip in the 132 kV voltage was only to 90 per cent of nominal voltage.

3.4 VOLTAGE RETURN

In order to evaluate the impact of the way voltage returns after fault clearance on FRT capability, a 3-phase short circuit was applied to the 20 kV system. The fault time and residual voltage follow the voltage curve, going down to zero, and vary at different points along the curve. One simulation was also made in which the grid voltage was forced to follow the voltage gradient exactly by changing the voltage profile of the 132 kV background grid. This is exemplified in Figure 8, where it is defined by the polygonal voltage return curve.

3.5 GRID STRENGTH

In order to evaluate the influence of the grid strength on FRT capability a local generator FRT response with different short circuit strengths (SCMVA) at the 132 kV system was simulated. The range was 50–1000 MVA. For a local generator of 8.7 MVA an SCMVA of 50 MVA represents a ‘weak’ system and 1000 MVA a ‘strong’ system. A 3-phase short circuit was applied on the 20 kV bus with a duration of 150 ms.
The graphs in Figure 10 show that the grid strength has an impact on the response of the generating set. The stronger the grid the less severe is the response of the generating set to a fault in terms of deviation in load angle. The grid short circuit strength has no impact on the initial speed deviation. However, the grid strength has a large impact on the response after fault clearing.

**CLICK TO VIEW FIGURE 11: SYSTEM VOLTAGE AND GENERATOR POWER RESPONSE IN A “WEAK” AND A “STRONG” ELECTRICAL GRID**

We can see from the simulations that in a stronger grid the voltage at the 20 kV bus will return to a higher value immediately after fault clearing. In this example 75 per cent of (U_n) for a weak and 85 per cent of (U_n) for a strong grid. This essentially means that the stronger grid was able to have a much higher retarding force effect that rapidly decelerated the generator and thus limited the maximum angle deviation. This impact is visible already with a moderately strong system, as Figure 10 shows.

What also can be seen in Figure 11 is that in the transient condition immediately after fault clearing, a synchronous generator might draw reactive power from the network to remagnetize in the same manner as a transformer or induction motor in a strong grid. Whereas this effect was not present in this simulation with a weak grid, reactive power at approximately pre-fault level was exported immediately after fault clearing.

It can thus be argued that unrealistic operation points and ambitious requirements in terms of active and reactive power supply immediately after fault clearing should be avoided because the amplitude and duration of the transient depend on the electrical grid to which the generator is connected and the severity of the fault. Local or cogeneration in the form of CHP plants, for example, is usually placed at or close to load pockets, where the grid strength can be expected to be relatively high. It could thus be argued that whereas grid strength is important for FRT, and should be specified in grid codes and used in the stability evaluations, extremely low values of grid strength that lie at, for example, less than about ten times the nominal power of the generator do not seem to be realistic in most cases.

3.6 ACTIVE AND REACTIVE POWER CONDITIONS

In order to evaluate the impact of reactive power conditions on the FRT capability, a 150 ms, 3-phase short circuit was applied on the 20 kV bus. The power factor was adjusted to between 0.95 leading and 0.8 lagging at the generator terminals.

**CLICK TO VIEW FIGURE 12: GENERATOR SPEED AND ROTOR ANGLE RESPONSE WITH POWER FACTOR 0.95 LEADING TO 0.8 LAGGING**

The operating point of a synchronous machine in terms of power factor before the fault is clearly affecting the response of the generating set. The critical clearing time is smaller when the machine is under-excited (leading power factor) than when the machine is over-excited (lagging power factor). This is because for under-excited operation, the initial load angle (δ) is higher, thus less synchronizing torque is available and the machine is closer to the angle at which it loses stability. With under-excited operation (power factor = -0.95) the generator lost synchronism at t=150 ms compared with t=200 ms for over-excited operation with power factor = 0.8.

In terms of stability the most demanding operational area for a synchronous machine is when it is under-excited. This is, however, not typical during operation. Most of the time, generators are operated at a lagging or close-to-unity power factor. Hence for FRT evaluation a lagging or a unity power factor could be used as this would represent a typical operation point.

4. CONCLUSIONS AND RECOMMENDATIONS

We can see from the simulations that a local generation unit driven by a reciprocating engine does not easily lose synchronism, even when subjected to such a severe and rare disturbance as a close-in 3-phase short circuit. Grid short circuit support is given during the fault and reactive power is exported following fault clearance. Similarly the generator set will resume its normal operation, exporting active and reactive power at its pre-fault operation point, within a very short time following clearance of the fault.

The ability to ride through the fault not only depends on the generating set but, to a large degree, on the state, strength and configuration of the electrical network before, during and after fault clearance. The simulations demonstrated this. The electrical network conditions are further bound to be time and location specific for any given operational state of the system or fictive in the form of a prescribed fault ride-through curve.

1. Fault clearance time: Reasonable fault clearance times are not only important for the stability of any network but also the faster the faults are cleared the less severe the consequences for everybody – network owners, consumers and generators. Unreasonable demands on prolonged fault clearance times based on delayed or backup protection may be too stringent for generators to accommodate.

2. Fault type: Three-phase faults are the most severe and lead to the most demanding situation for the generating set. However, it has to be remembered that most faults in transmission and distribution systems are 1-phase to ground. Three-phase faults are rare.

3. Level of voltage dip: A fault in which the voltage at the interconnection point drops to zero in all three phases is the most demanding for the generating set. The final residual...
4. Voltage return. The voltage return curve has a large impact on a generator’s ability to remain in synchronism. A very slow voltage return as mandated by some grid codes is very demanding and might be too stringent for local generators to accommodate. A square-shaped voltage return seems to be a more realistic way of defining FRT requirements.

5. Grid strength: The strength of the grid at the interconnection point has an impact on the generator’s ability to stay in synchronism. The stronger the grid the less adverse the deviations in load angle. However, with a moderately strong system the impact of the grid strength is not pronounced.

6. Active and reactive power conditions: The operation point in terms of reactive power has a significant impact on the generator’s ability to stay in synchronism for a close-in short circuit. Operation with a leading power factor is the most demanding situation.

7. Active and reactive power after fault clearance: It is important to recognize that there is a transient condition following fault clearing with an active and reactive power swing. The amplitude and duration depends on network conditions, fault severity and generating set inertia and control.

In any system rare combinations of circumstances that may produce instability can always be found. Such extreme conditions might result in unreasonable demands on the FRT capabilities of local generators. In particular, if these are required simultaneously it might create situations that cause a generating set to lose synchronism, so it is important that the conditions required for FRT are reasonable and well defined. Unreasonable combinations of requirements in such terms as voltage being depressed for a prolonged time after fault clearing, or overly long fault clearance times, in combination with abnormal operation conditions such as operation on under-excitation and undervoltage, might lead to FRT conditions that may not be met by commercially and technically viable equipment.

There is a need, therefore, for sound engineering judgement over which conditions should apply to any given case and network. Conditions should also reflect the differences in basic technologies and respect physical and economic restrictions. The background is that different power generating technologies have different physical and operational restrictions, as well as advantages.

Designing for absolute extremes or unlikely operating conditions is neither economical nor desirable in the long run as desired features, such as high efficiency, might have to be sacrificed to fulfill extreme contingencies. It is thus recommended that there is a continuous dialogue between equipment manufacturers, regulators and transmission and distribution operators to create reasonable rules for fault ride-through capabilities and interconnection rules in general.

4.1 REMARKS
This paper has described how the conditions in electrical grids to which generating sets are to be connected are not fixed and are bound to be time and location specific. Evaluation of FRT capability by simulation seems to be the best option to demonstrate FRT capability.

Given the many benefits of local electricity generation based on reciprocating engine sets, including its ability to ride through severe network disturbances, it is undoubtedly an important contributor to balance locally or centrally electricity networks that face an ever increasing demand for power. Such an efficient, flexible, reliable and dynamic source of electricity is a must.

4.2 WARNING
It is important to recognize that the diagrams and conclusions on dynamic performance as given in this paper are the results of simulations and are therefore only approximate.
REFERENCES


OPENING KEYNOTE: AGREEMENT ON NEED FOR BALANCED GENERATION MIX

Discussing their visions of the future of power generation across Europe and the rest of the world, the former Dutch prime minister Ruud Lubbers, Masdar Power’s chief executive Frank Wouters, and Joost van Dijk, chief executive of E.ON Benelux opened proceedings with the Joint Keynote Session.

Perhaps unsurprisingly, one of the overriding themes shared by all the presentations at this session was the importance of environmental issues, climate change, and more specifically cutting carbon dioxide (CO2) emissions. There was also consensus that the demand for energy is set to increase significantly, and that the solution to this dichotomy lies in ensuring a balanced mix of power generation technologies.

Speaking with reference to the Dutch aim of reducing CO2 by 50 per cent from 1990 levels, as set out in the Rotterdam Climate Initiative, Lubbers believes the road ahead will need to be a combination of carbon capture and storage (CCS), efficiency improvements to current generating technology and a significant increase in renewable energy output. To a great extent this was a view held by all the speakers.

Giving us a brief of Masdar’s ‘democratic energy’ vision, Wouters cited the massive success of solar photovoltaics in Germany, that saw some 2.3 GW installed in just three months in late 2009. This was mostly the result of individuals and organizations purchasing and installing their own generating capacity, and is perhaps the best current example of the decentralization of the installed generating capacity. “Democratic energy means that the market will dictate the direction to the industry,” said Wouters.

Carbon capture was another theme common to the three presentations. Following on from Lubbers’ call for the expanded use of CCS as part of a balanced approach to power supply, van Dijk went on to explain how an E.ON project in the Netherlands will be capturing and storing as much as 1.1 million tonnes of CO2, in a location approximately 25 km offshore, by 2015.

There was general agreement that the coming years and decades will see a transition in the way we both generate and consume electricity. Vehicles will, to a much greater extent, become electrified, the world’s population will expand and its economies will grow. Our power generation must keep pace. We will need a blend of clean coal, gas, nuclear and renewables, as well as a T&D infrastructure that can accommodate all this.

THE FUTURE SHAPE AND REQUIREMENTS OF EUROPE’S UTILITIES

At the POWER-GEN Europe conference, leading companies in the utilities sector shared their vision for the future of the industry. All agreed that the industry needs to focus on achieving carbon neutrality by 2050, creating a cost efficient and reliable supply of energy through an integrated market, and enabling energy and electricity to be used as solutions to mitigate climate change.

However, the decarbonization of power generation is only viable with a mix of renewables, nuclear and CCS.
According to Hans ten Berge, secretary general of Eurelectric, 38 per cent of energy will come from renewable energy sources, 27 per cent from nuclear, 30 per cent from CCS and 5 per cent from other fossil fuels by 2050.

“The target of achieving carbon neutrality by 2050 is realistic but will require all power generation options, electrification on the demand side, and significant investment at a level that is acceptable to society,” ten Berge.

José Luis del Valle Dobaldo, chief strategy and research officer for Spain’s Iberdrola believes the next ten years will be a decade of transformation and that in the future technological progress in wind power generation will enable wind to play the most significant role in power generation. He also stated that Smart Grids will need to play a role as a transformation platform in order to support the move to renewable power supply and facilitate efficiency and energy services. “Ultimately a lot will depend on the industry’s ability to balance environmental and affordability objectives,” del Valle concluded.

Pedro Neves Ferreira director of Energy Planning for Energías de Portugal agreed that the rising price of fossil fuels and growing dependency on energy along with climate change will shape energy policy in the future.

What was made clear by all the panel is that well planned investment strategies will play a key role in the future of the utilities industry. Mick Mackay, head of Engineering of ESB International, Ireland, outlined the importance of best practice project delivery in ensuring the success of any investment project, emphasizing that the key to future success lies in clear governance models and strategic resource planning with best practice project delivery essential.

SMART GRID, A PLATFORM FOR INNOVATION

The Smart Grid Vendor Panel took place as part of the POWERGRID Europe conference programme and enjoyed an impressive turnout of attendees and speakers.

Chaired by Kathleen Davis, PennWell conference director, the panel session brought together 11 leading figures from the industry. The panel was selected to represent a wide range of perspectives and to be able to give a balanced global picture.

It was clear from the early discussions that the consumer was becoming a key part in the future of the Smart Grid, with the panelists agreeing that educating the consumer on the benefits of a Smart Grid was vital. However, the definition of the Smart Grid was something that all panelists felt was a slightly ambiguous term, and difficult to explain to the consumer.

Peter Arndt of Trilliant, a Smart grid communications company, suggested that the Smart Grid should be positioned as the Internet for utilities. This was seconded by Rolf Adams from Cisco, who added that, like the Internet, the Smart Grid is a platform for innovation, but that it must be scalable. Members of the audience were particularly interested in the contrasts between the Smart Grid and the Internet. Interested listeners suggested that the Smart Grid is currently where the Internet was ten or 15 years ago, and to contrast the two is helpful, especially as both have the distribution of information at its core.

The panel discussed the shift that the Smart Grid – and smart meters – have experienced, from initially being a utility-centric product to a more consumer focused service. Adams believes that the Smart Grid can provide the consumer with transparency, which he saw as an essential factor in the growth of the market. Although the panel agreed that the concept of the Smart Grid was good for consumers, there were issues that some believed needed ironing out, namely security and privacy.

After the event, panelist Paul Dacruz, global vice president of Power at Invensys, said: “I think there was great interaction between the vendors, and it was great to get a wide range of opinions from the vendors, and it was great to get a wide range of opinions from different countries. The smart grid is an important concept, but a large one as well, so there was much to talk about.”

PROGRESS REPORT: NUCLEAR PLANTS UNDER CONSTRUCTION

A fascinating session in the Nuclear Power Europe conference updated delegates on the progress of new Generation III+ reactors currently under construction.

Monica Frogheri of Italy’s Ansaldo Nucleare shared details of the AP1000 plant in China, a project that is being undertaken by Ansaldo Nucleare in partnership with Westinghouse. Frogheri reported that as a result of the well planned approach taken by both organizations the construction project is currently on schedule. The first two units will be operational in May 2013 and 2014 following 12 months of evaluation and 50 months of construction.

In sharp contrast to the apparent smooth running of the AP1000 project, David Emond, deputy project director for Areva, discussed the ongoing challenges faced by the seemingly ill-fated Olkiluoto project in Finland. Despite over 24 million man hours being spent on the project to date, the project is now four years behind schedule.

However, Emond was keen to stress that although there had been a number of difficulties with the project, important lessons have been learned that will serve the industry well for the future. In particular, the importance of having close cooperation between
all parties involved from the very beginning and discussing all elements of the project in fine detail before any work on the project begins. Emord also emphasized that the importance of safety and communicating this effectively to all parties involved should never be underestimated.

At the end of the session, Jukka Laaksonen, director general of Finland’s Radiation and Nuclear Safety Authority (STUK), shared his opinion on the valuable lessons learned from the Olkiluoto 3 project. He felt that some of the most significant problems with the project were a result of the lengthy delay between the signing of the project contract and the start of construction.

This came at a time when the parties involved were not ready to start work at that time – the skills were not in place, the designs were not ready and the experience was not there. Laaksonen also pointed out that one of the main reasons the project has slipped so far behind is because the original schedule for completion was simply unrealistic.

PLENARY TACKLES CLIMATE CHANGE & RENEWABLE TARGETS

The recession and ongoing economic uncertainty in the EU have cut emissions levels, but accurate price signals still are needed to help consumers make decisions about energy efficiency and renewable investments.

Those were the broad conclusions reached during the Plenary Panel Discussion, “Climate Policy Uncertainty: Where Does the Power Industry Go from Here?”. Moderated by TV presenter and journalist Stephen Sackur and streamed live over the Internet to a worldwide audience, the panel of seven industry leaders tackled a range of issues.

“We want people to look at the real costs and make rational decisions,” said Joan MacNaughton, Alstom Power Systems’ senior VP for Power and Environment Policies. The targets are helping to cut emissions and the EU is showing greater certainty over legislation and policy than countries such as the United States. She admitted, however, the EU political framework “could be better.”

“In the EU emissions are going down,” said Matthias Hartung, CEO and president of RWE Technology. “The next step is to reduce emissions cap.”

Stephen Kidd, Director of Strategy & Research for the World Nuclear Association, said energy “has been too cheap” and that efficiency gains can be best achieved by making energy more expensive. David Porter, CEO of the UK’s Association of Electricity Producers, added that higher prices will drive efficiency. “The days of cheap energy are long gone,” he said, but pointed to a “serious weakness” around the price of carbon. “The EU scheme works, but what is missing is the [right carbon] price.” Iain Miller, former CEO of Doosan Power Systems, UK, said carbon pricing is not currently working, but that European policymakers are showing a willingness to set a price floor to help incentivize investments in nuclear, clean coal, natural gas and renewables.

Sackur called efforts in Copenhagen last December to reach agreement on climate change targets a failure and asked panelists for a show of hands if they thought follow-on efforts to reach agreement this coming winter in Mexico would prove more successful. No panelists volunteered to raise a hand. Nevertheless, the panel was reluctant to say Europe should reassess its goals for 20 per cent renewables by 2020.

MacNaughton said the targets may be at the low end of what needs to be accomplished. She called the related investment challenge “huge” and said policymakers would not ease uncertainty by changing targets.

However, Rainer Hauenschild, CEO of Energy Solutions for Siemens, countered this view by saying the 20 per cent goal was already a “challenge” and “a lot of things have to work” to reach the goal, including enhancing the grid and distribution networks and providing back-up power to renewable energy. “We have to move toward the targets but there is not one technology” to do so, he said.

Carlo Luzzatto, co-general manager of Ansaldo Energia, agreed and said it is “nonsense technically” to discuss 100 per cent renewables as a European target by 2050. “We need to combine renewable energy with conventional sources, not only for grid stability but also for power quality purposes and security of supply. There is always going to be a combination of all sources on the Smart Grid.”

THE OPTIMAL MIX FOR A RENEWABLES PORTFOLIO

The plenary session at the Renewable Energy World Europe conference was also a heated debate between speakers from organizations with scopes as dispersed as the Americas, Europe and Asia.

They represented a range of interests, including the National Renewable Energy Laboratory (NREL), a research and development organization who also advises the US government, EnBW Renewables, a German power utility and Juwi Wind, a greenfield developer of power production projects. There was a consensus reached, which was focusing on just one renewable technology when investing is too risky an approach. However, the specific
technology to invest in and the future factors affecting the balance of renewables provoked much greater controversy.

When thinking about the risk reward of various renewables cost must certainly be looked at. It was agreed amongst the panel that all of the technologies available onshore wind is the most economical form, whilst offshore wind is the most expensive. However, this is not the only element which contributes to cost because you must also consider the expense of getting the power from where it is created to where it needs to go and the varied pricing strategy of power usage which means that profits are potentially greater if power is produced during peak demand.

Marie-Luise Pörtner, managing director of Juwi Wind, is working towards a 100 per cent renewable mix and believes that it is a case of when this happens, rather than if it will. Juwi Wind concentrates on onshore wind and believes that the real power of renewables is in its potential to make a huge change to power production in communities.

“It is this decentralization of control and autonomy which will have the most notable effect and should therefore be considered when looking at investment,” she said.

The counter to this belief, as Werner Götz, general manager of EnBW Renewables, suggested, is that renewable power generation is in fact still going to be policy-driven. If this is the case, proposed legislation and support should therefore be the major consideration when looking at the future development of different technologies.

He believes legislation will still have a great impact on renewables as the public are reaching the point where they are no longer willing to accept any more power production in their back garden. The renewables industry is certainly experiencing growth but it must be remembered that it is still a relatively nascent and small investment community which is also rapidly changing. This means it needs constant monitoring as to where businesses should look to build-up their portfolio.

POWER INDUSTRY’S FUTURE. WHAT THE DELEGATES THOUGHT
Delegates were asked their own opinion about the lack of clarity left by the Copenhagen talks and around 70 per cent felt that this either was, or could have, a negative impact on the power industry. Those polled were less clear about whether the EU will be able to meet its target for total energy consumption from renewable of 20 per cent by 2020 with responses about equally divided between the ‘yes’, ‘no’ and ‘too early to say’ options.

But there was optimism among delegates about trading conditions in the coming 12 months, with three quarters of respondents believing that a strengthening in power equipment and services markets will occur.

When asked about which sector will be the most active between now and 2015, around 40 per cent thought that renewables would see most activity, followed by 28 per cent who believed that upgrades and refurbishment would take the lion’s share of the market. Interestingly, around a quarter thought that nuclear power would be the hottest market over the next five years.

We look forward to welcoming you to POWER-GEN Europe and its co-located events next year, which take place in the cosmopolitan Italian city of Milan, 7-9 June 2011.