Combustion Challenges for Gas Turbine Operators of Changing Fuel Gas Compositions

Dr David Abbott
CU Visiting Fellow

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www.cranfield.ac.uk

Changing Fuel Gas Compositions

Intended Outcomes.
Following this lecture you should be able to:

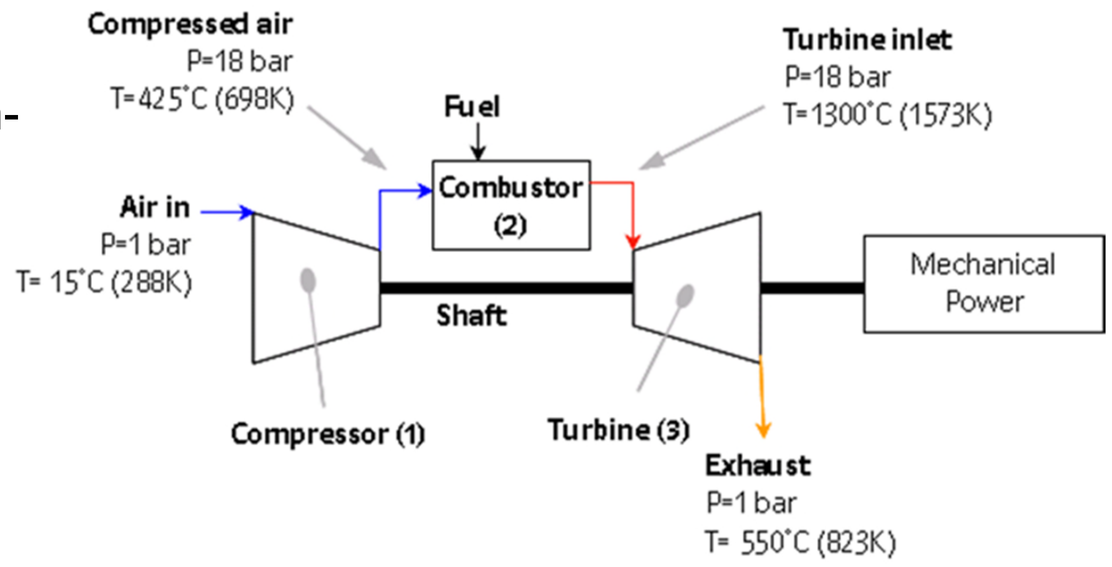
- Outline the range of gaseous fuels that gas turbines can accommodate
- Identify the issues associated with natural variations in natural gas composition
- Describe the impact of widening the allowable range of fuels in the gas transmission and distribution system
- Describe the impact of new and renewable gases such as biogas, biomethane and hydrogen
- Identify potential mitigation measures to deal with variations in fuel composition

Background

What gases can gas turbines burn?

It is often said that gas turbines can burn (almost) any combustible gas. There are gas turbines capable of firing:

- Natural gas (including NG with high inerts and high non-methane hydrocarbons)
- Landfill gas, Sewage gas, Digester gas
- Wellhead gases
- Syngas from coal, biomass and wastes
- Steelworks gases: COG & BFG
- Very high hydrogen gases (e.g.refinery gases)
- and more...



BUT each individual gas turbine can only tolerate limited changes in gas composition and properties, depending on the gas turbine design and set-up ***and*** some gases may have an adverse impact on component life.

Natural Gas: What is Natural Gas?

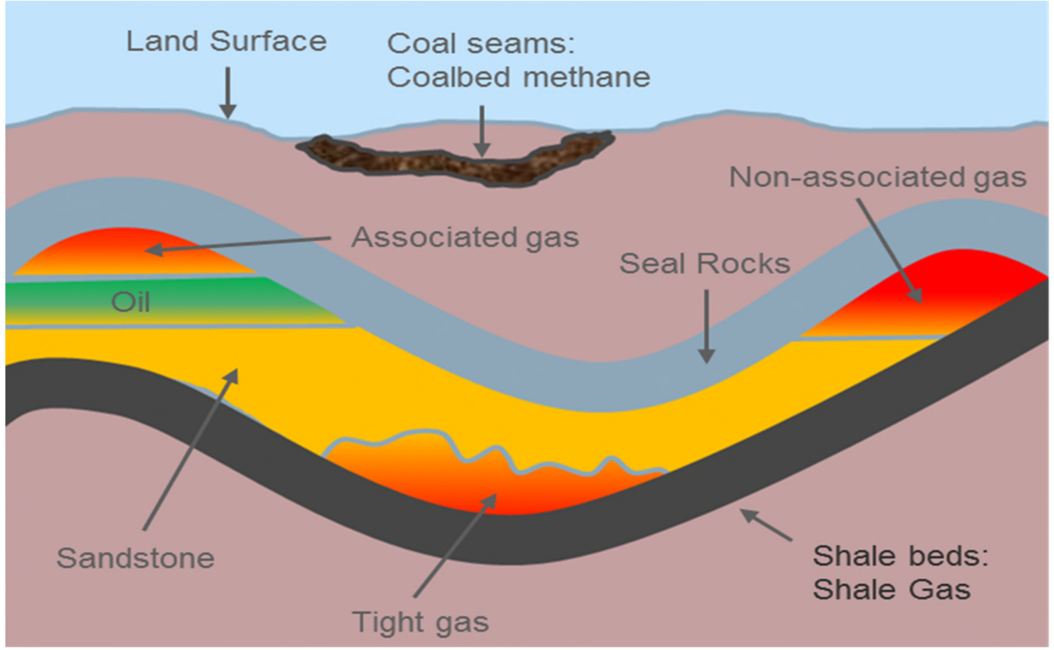
- The majority of modern land based gas turbines are designed primarily to operate on natural gas
  - Gas turbines offered for other gaseous fuels are normally derivatives of natural gas firing machines

- The main source is thermogenic gas:

  Organic material is degraded by the earth's heat

  - Conventional
    - Non-Associated Gas
    - Associated Gas

  - Coal Bed Methane (CBM):
    - Virgin CBM, Mines Gas, Abandoned Mine Gas



- Shale Gas: Requires “Fracking” to release gas from the rock structure

- Tight gas: held in rocks (typically sandstone, sometimes limestone) with even lower permeability than shale

Natural Gas: What is Natural Gas?

Other sources:

- Biogenic gas
  - Formed by decomposition of organic matter by anaerobic microorganisms.
  - Accumulations found in Canada, Germany, Italy, Japan, Trinidad, the United States, and USSR
- Methane Hydrate (Methane Clathrate: $(CH_4)_4(H_2O)_{23}$)
  - Found in:
    - Sedimentary rocks in polar regions (Alaska & Siberia)
    - Deep water sediments at low temperature

Typical components in natural gas

Alkanes other than methane are referred to as higher hydrocarbons or C2+

	Minimum	Maximum
	% vol/vol	% vol/vol
Inerts		
Nitrogen	0.1	7.7
Carbon Dioxide	0	4
Alkanes		
Methane	82	97
Ethane	2.8	10.2
Propane	0.1	3.7
iso-Butane	0.01	0.44
n-Butane	0.01	0.75
neo-Pentane	0	0.055
iso-Pentane	0	0.25
n-pentane	0	0.17
n-Hexane	0	0.015

Composition based on UK National Grid "Safety Data Sheet, Natural Gas", 2006
Note: Min - max ranges may be different in other locations.

	Minimum	Maximum
	% vol/vol	% vol/vol
Aromatic and Cyclic Hydrocarbons		
Benzene	0	0.015
Cyclohexane	0	0.0015
Toluene	0	0.001
Xylenes	0	0.001
Sulphur Compounds		
Hydrogen Sulphide	0	0.0003
Others		
Mono Ethanol Glycol	0	0.01
Petroleum Distillate	0	0.0003
Ethyl Mercaptan	0	0.00002
Tertiary Butyl Mercaptan	0	0.00013
Dimethyl Sulphide	0	0.00004
Di-ethyl Sulphide	0	0.0001
Methyl Ethyl Sulphide	0	0.00002

Key Fuel Parameters

- Comparison of fuels based on detailed fuel composition is difficult unless derived parameters are used such as:

  - Mass based calorific value (heating value)
  - Volume based calorific value (heating value)
  - Density
  - Relative Density
  - Wobbe Index
  - Higher Hydrocarbon Content (C2+, C4+, C6+)
  - Inert Content (N_2, CO_2...)

  - Sulphur compounds
  - Contaminants

... and many more

Key Fuel Parameters: Wobbe Index (Wobbe Number)

- Commonest parameter for specifying fuel acceptability in Grid and Manufacturers' Specifications is Wobbe Index (WI)

$$WI = \frac{Calorific\ Value\ (volumetric)}{\sqrt{Relative\ density}}$$

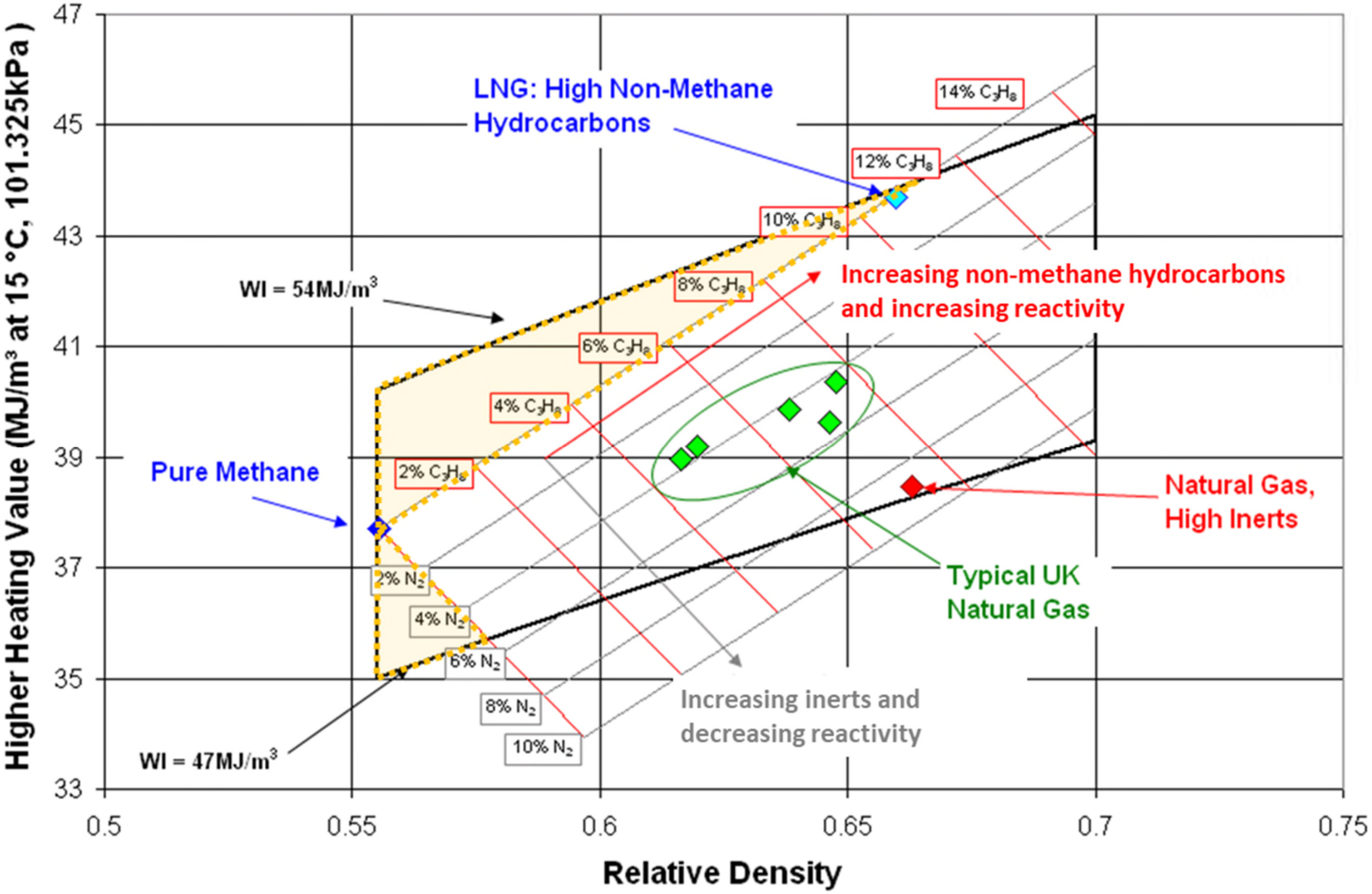
- For given fuel supply and combustor conditions (T and P) and given control valve positions two gases with different compositions, but the same Wobbe Index, give the same energy input
- Beware:
  - WI is not a dimensionless number and can be defined based on either Gross or Nett Calorific Value
  - As it is based on VOLUMETRIC calorific value, reference conditions are important
    - Net or Gross and reference temperatures and pressure should be stated
  - Some manufacturers use a Modified WI that takes into account fuel delivery temperature

Key Fuel Parameters

- Most gas turbines can be set up to run on a wide range of WI by minor modifications (e.g. minor fuel nozzle changes) and modification of control parameters, but once set up only tolerate limited changes:
  - Standard gas turbines typically allow a WI range of ±5%
  - But some allow a range as low as ±2%
- In addition to WI, detailed composition affects:
  - flame speed
  - autoignition properties
  - flame chemistry etc.
- Manufacturers' specifications for composition vary, but often specify
  - maximum levels of higher hydrocarbons (individually or as C2+, C4+ etc),
  - minimum methane and/or maximum inerts.
- Grid Specifications often limit Relative Density to restrict the range of composition

Heating Value-Relative Density Plot

- Often used to compare gas compositions
- The plot show the allowable range of fuels for a specification of:
  - 0.555 < RD < 0.7
  - 54MJ/m^3 < WI < 47MJ/m^3
- Fuels with properties in the regions shaded: cannot be created with normal constituents of natural gas



Changing conditions for Power Generators

- Changing fuel composition (within current specifications)
- Widening delivery specifications
  - Green Gas (Biomethane, Bio SNG ...) injection
- Hydrogen injection
  - Power to Gas (P2G): hydrogen as an energy storage vector
  - Low carbon hydrogen (see colours)

- Opportunity fuels
  - Waste gases: refinery gases, process gases, gasification gases, LNG boil-off-gas

- Emissions legislation
- Life and interval extension
- Operational flexibility
- Economics

Colours of Hydrogen

Green: water electrolysis using renewable electricity

Blue: from fossil fuel with CO_2 capture or use (CCSU)

Turquoise: methane pyrolysis producing solid carbon.

Purple: nuclear power and heat through combined chemo-thermal electrolysis of water.

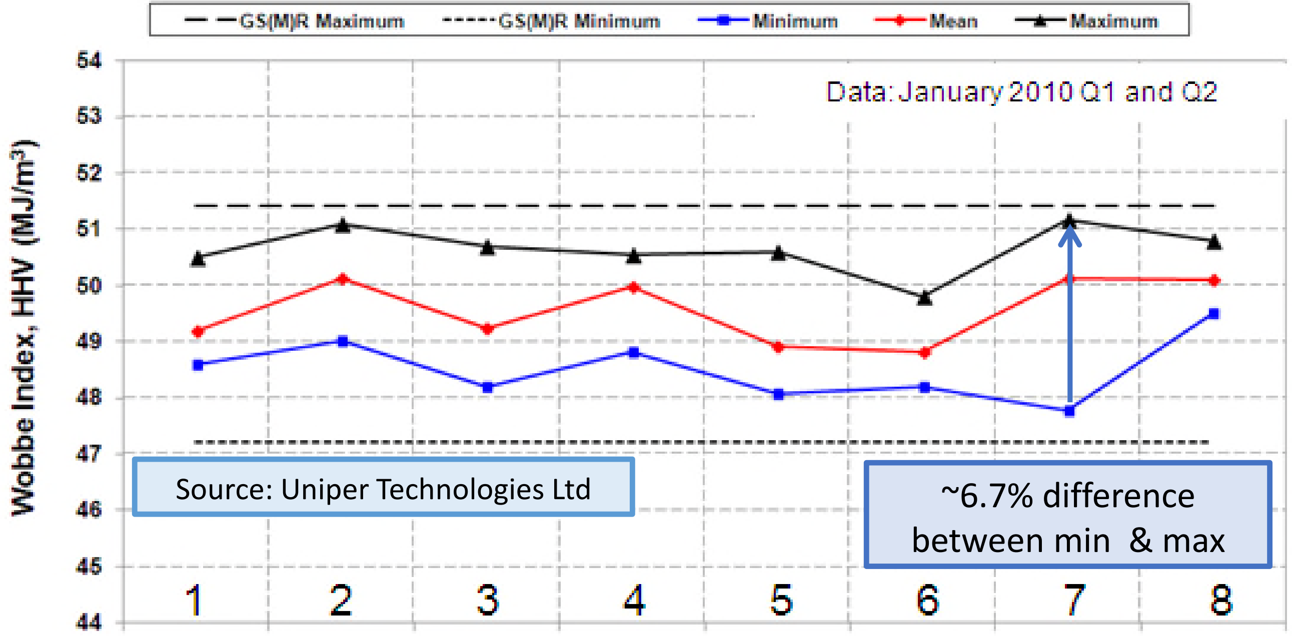
Pink: water electrolysis using electricity from a nuclear power

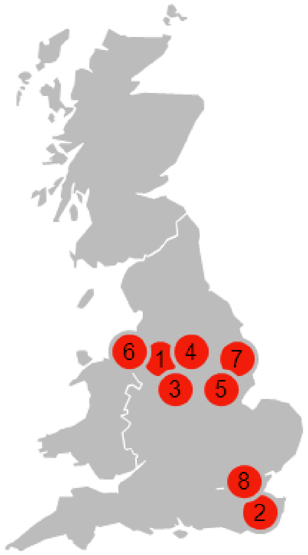
Red: high-temperature catalytic splitting of water using nuclear power thermal energy

Gray/Black/Brown: From fossil fuel no CO_2 capture

Variability of WI in the UK

- UK fuel delivery specified by the Gas Safety (Management) Regulations
  - Normal Wobbe Index Range 47.20 to 51.41MJ/m^3 (@ 15°C, 15°C, 1.01325 bar)
  - Proposed change: reduce lower limit to 46.5MJ/m^3
    - Will allow Bio methane and natural gas with higher level of inerts
  - Wider changes were initially proposed and have occurred on other countries





	GS(M)R	Proposed	
Upper	51.41	51.41	MJ/m^3
Lower	47.2	46.5	MJ/m^3
Midpoint	49.305	48.955	MJ/m^3
Range	4.21	4.91	MJ/m^3
Range ±	4.27	5.01	(%)

Remember: Typical gas turbines can tolerate ±5% variation in WI (from tuning fuel)

European Gas Quality Harmonisation

- European Standard: EN 16726:2015 set standards for a wide range of parameters including:
- Relative density (0.555 to 0.700)
- Sulphur and sulphur compounds, oxygen, carbon dioxide
- Hydrocarbon and water dew points
- Methane Number (65)

- EN 16726 Appendix D states:

One of the objectives of this standard was to define a common CEN Wobbe index range ...
After many controversial discussions and manifold approaches, the CEN/TC 234 and the involved stakeholders/partner organisations concluded that the definition of a commonly accepted European Wobbe index range is not possible at the moment and that further analyses are required prior to setting minimum and/or maximum values. The EU Commission DG ENERGY monitored the discussions and formally accepted the CEN/TC 234 conclusion.

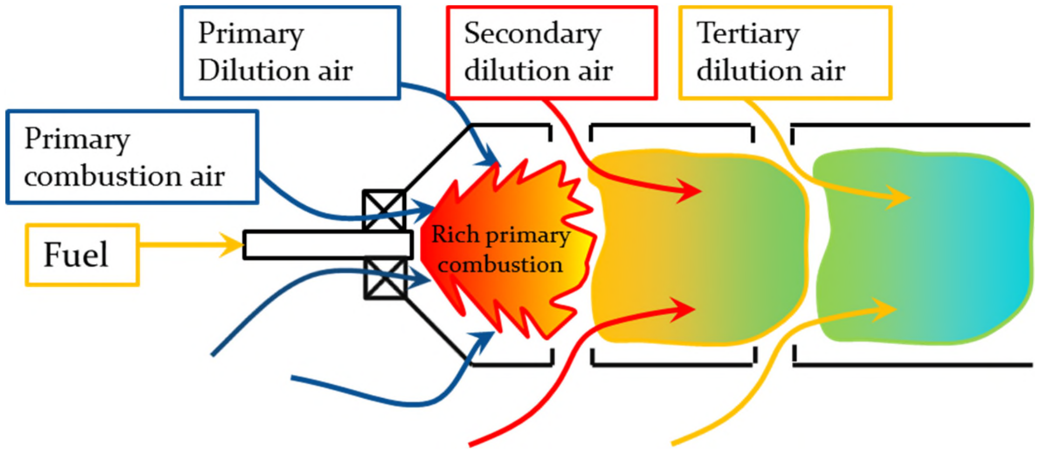
The starting point for discussion was the EASEE-gas CBP: $46.4 MJ/m^3 < WI < 54 MJ/m^3$ (@ 15°C, 15°C, 1.01325 bar) (±7.5%)

- **Discussions are still underway and a range of options (including different criteria in different zones) are being considered**

Reminder:
Typical GT Combustion Concepts

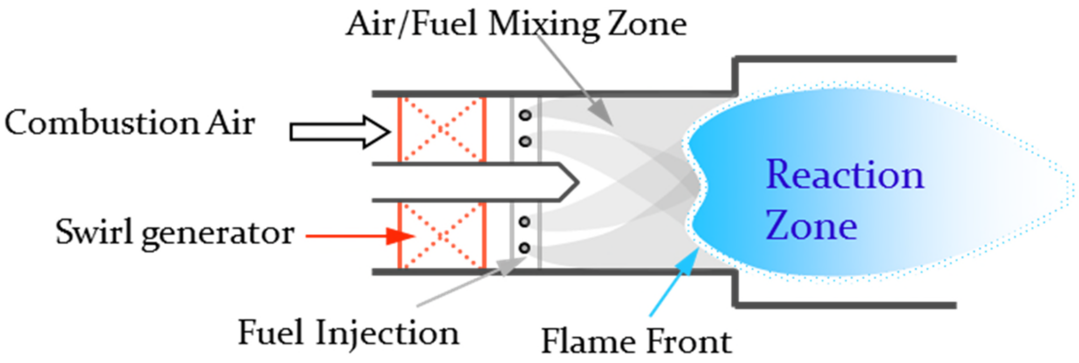
Diffusion Combustion:
- Air/fuel mixing in combustion zone
- Wide spread of fuel concentrations

Gives:
- Stable, efficient combustion
- Wide operating envelope
- Flashback resistant
- High NO_X emissions



Lean Premix Combustion:
- Air/fuel mixing before combustion zone
- Lean Combustion

Gives:
- Low NO_X emissions
- Potential for flashback
- Issues with stability and dynamics
- Need for careful combustion tuning



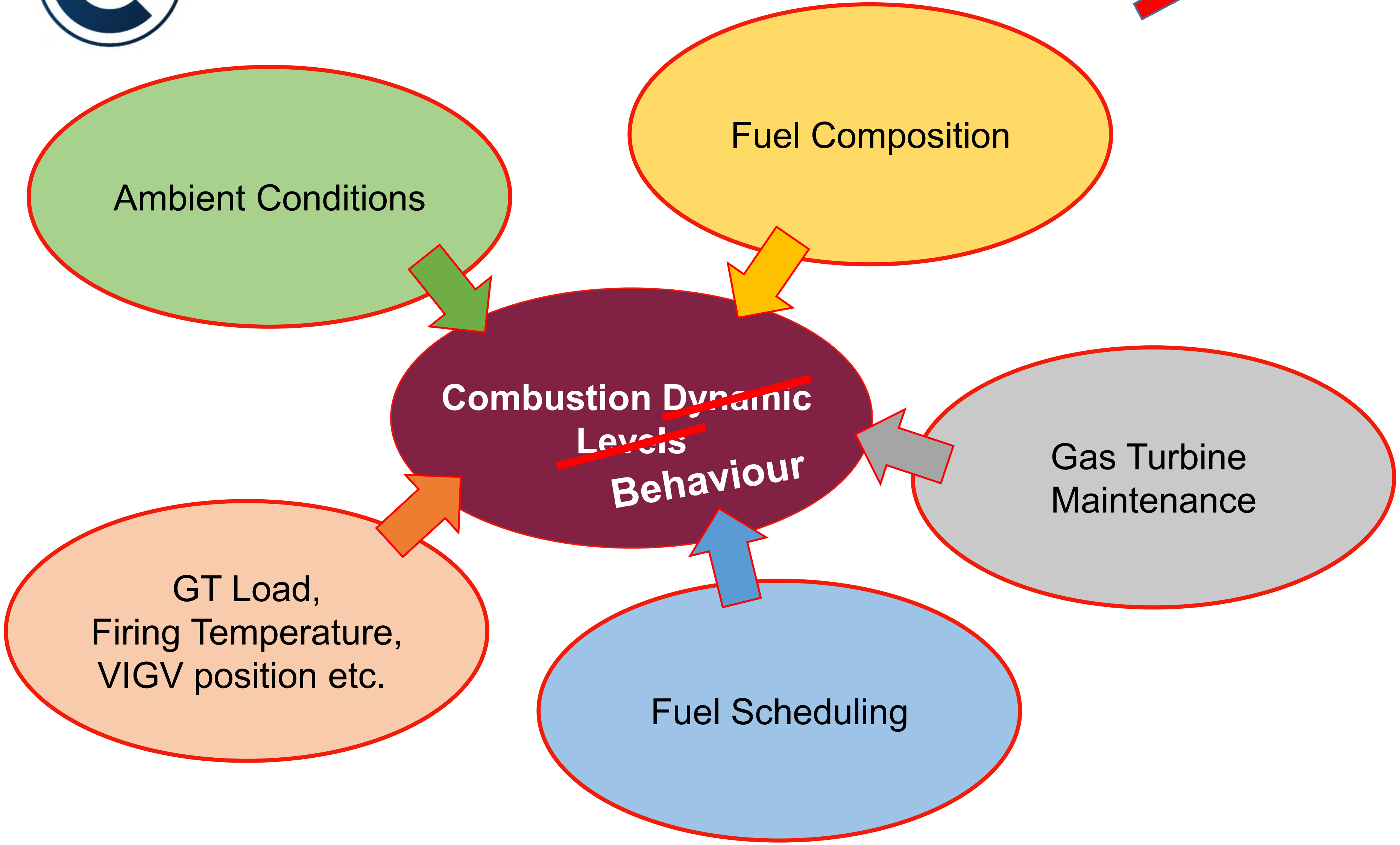
Reminder:
Combustion Dynamics (Humming, pulsations, etc.)

- All flames produce some noise due to turbulence, fluctuating heat release etc.
  - This noise is typically broadband in nature and is not normally of sufficient amplitude to cause problems

- Under some circumstances, particular acoustic frequencies are favoured and high amplitude narrowband noise can occur causing:
  - Component wear
  - Reduced component life
  - Catastrophic failure

Impact of Fuel Variation

Factors That Affect Combustion ~~Dynamics~~ Behaviour



- Emissions
  - NOx , CO
- Flame shape and position
  - Flashback
  - Blow-off
- Dynamics
- …

Impact of WI and Fuel Composition

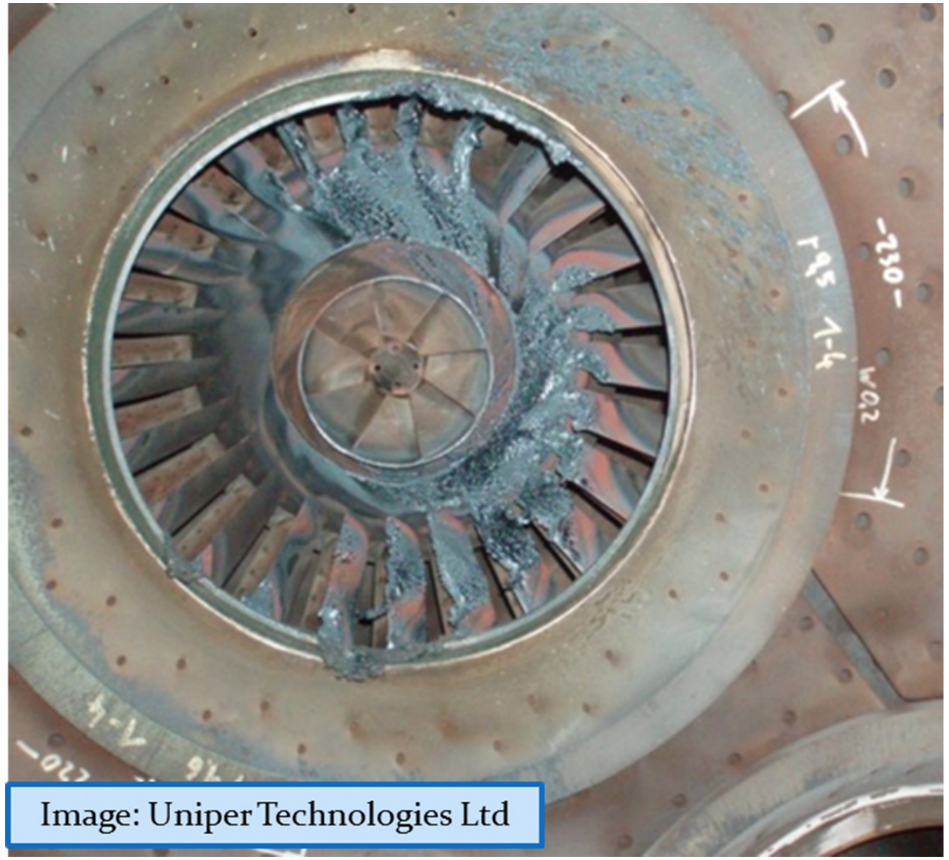
- Flashback risk increases with increasing C2+
  - Component damage, trips & de-loads
- Increases in dynamics with changing C2+ or changes in Wobbe Index
  - Component wear/damage, trips & de-loads
- Flame stability issues with reducing Wobbe Index (leading to dynamics and part load CO problems)
  - Emissions issues, trips & de-loads
- Increasing NO_X with increasing Wobbe Index
  - Emissions issues, de-loads
- Flame stability issues and high part load CO with low C2+
  - Emissions issues, trips & de-loads
- Control issues with rapid change in fuel composition
  - Trips & de-loads

Example 1: Flashback

- High levels of higher hydrocarbons (C2+) increases reactivity
  - flame speed increases
  - autoignition delay time decreases
    - Flame may propagate upstream or autoignition may occur causing flashback damage
- High levels of C2+ can result in condensation of liquid hydrocarbons, causing similar results

- Hydrogen increases reactivity in a similar way to C2+ and flashback risk is a significant concern for hydrogen blends

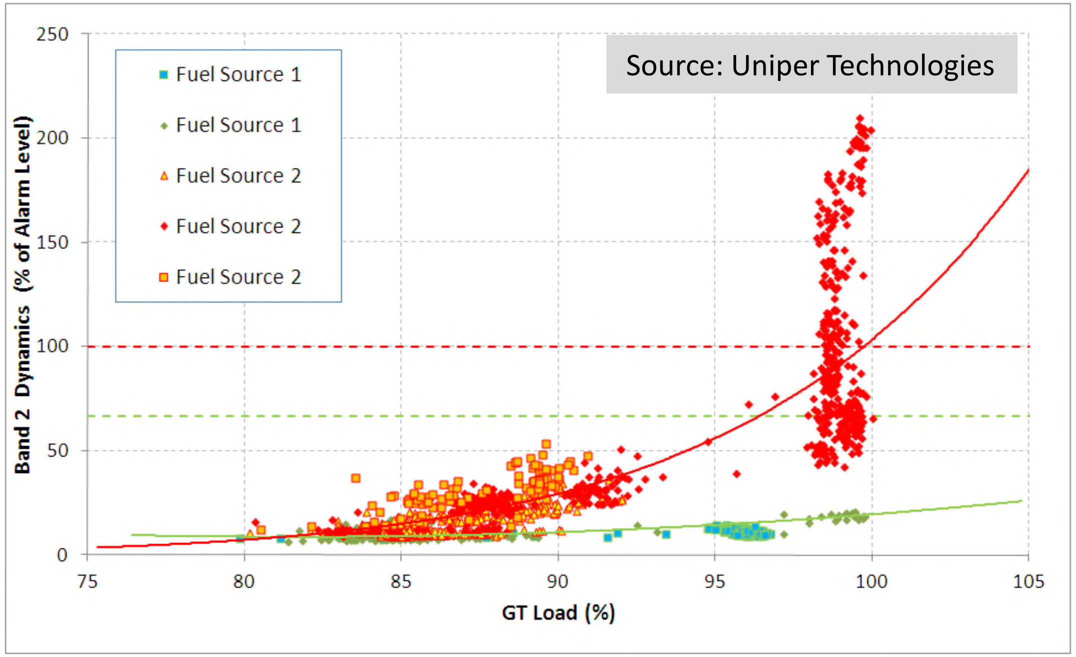
- Most modern burners are relatively flashback resistant, but adding hydrogen may cause problems



Damage as seen here has been attributed to flashback due to high levels of C2+

Remember:
Example 2: Impact of High C2+ on dynamics

- Site with multiple natural gas sources
- Alert and Alarm levels set for protection
- Operator to act to prevent levels above *Alarm* if possible
  - Levels exceeded Alarm
  - Load restricted (to ~95% load)
  - NO_X increase also seen
  - ***All fuel was within specification***

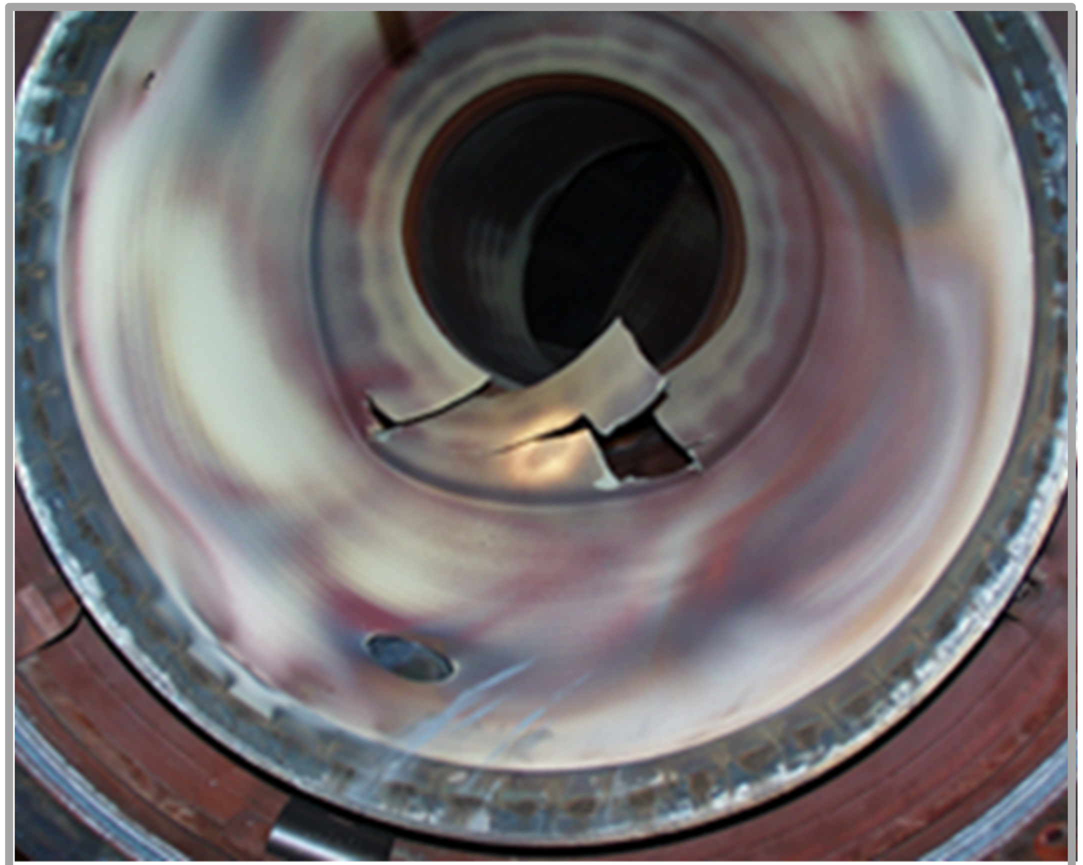


- Tuned on Fuel Source 1 (Higher hydrocarbons, C2+ ~7%)
- High dynamics when firing Fuel Source 2 (C2+ ~11%)

- Had been tuned for very low NO_X emissions
  - Insufficient margin allowed to accommodate fuel changes

- Retuned for acceptable dynamics on both fuels
  - NO_X increased by ~10%, but still well within Permit Levels

Remember:
Example 3: Failures linked to dynamics



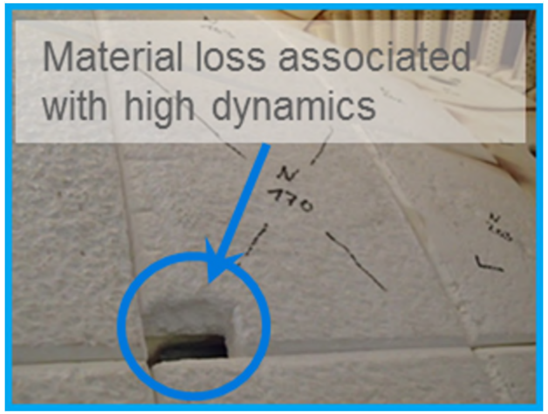
Mechanical failure linked to medium frequency dynamics (~150Hz) which can be linked to rich combustion, high Wobbe Index or high C2+

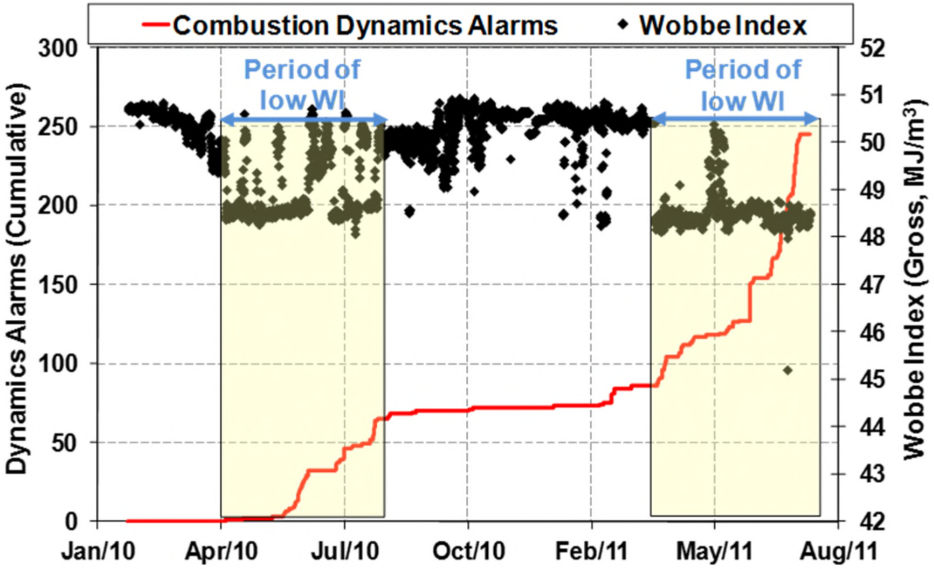
Damage following mechanical failure due to high frequency dynamics (~2kHz) which can be linked to fuel changes

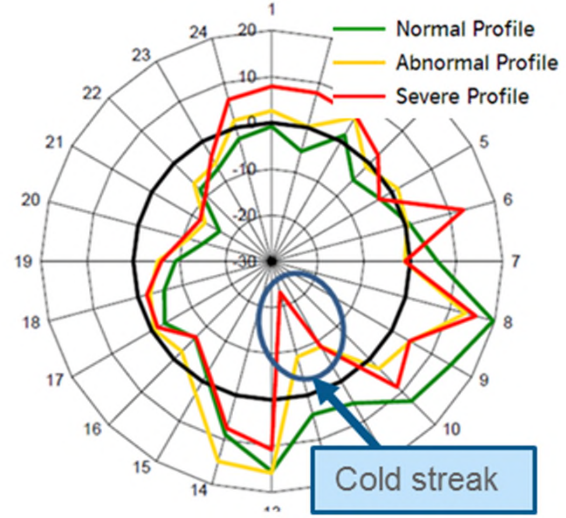
Example 4: Impact of Wobbe Index on flame position, dynamics and part load emissions

- High rate of dynamics alarms and de-loads when WI was low
  - Cold streak in exhaust indicating flame lift-off on one burner
  - High part load CO emissions
- Lowest flowing pilot was insufficient to maintain flame stability when WI was low causing partial flame lift

⇒ Changed flame dynamic response

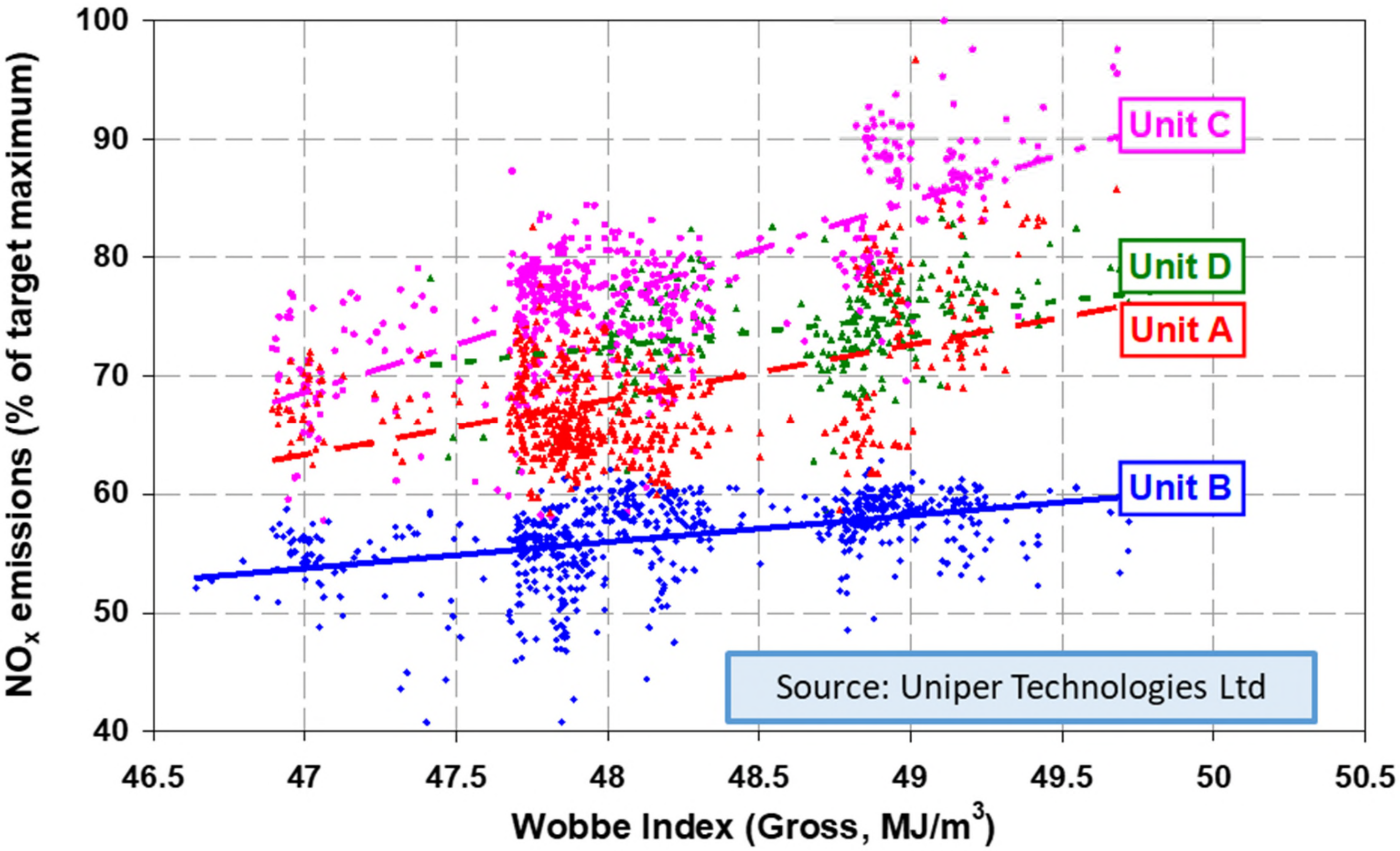






Example 5: Impact on NOX Emissions

- Site with four GTs of same design
- Increasing trend in NOX emissions with fuel Wobbe Index
- Impact of fuel quality on NOX emissions varies between the 4 units



Example 6: Low C2+ and CO emissions

- On more than one engine type, problems have been observed when the C2+ is too low (thus methane content too high)

- Relatively speaking, methane is not as reactive as higher order alkanes
- Under certain conditions, typically part load when flame temperatures are lower, not enough energy to fully oxidise CO to CO_2.
- Combination of not enough C2+, plus low temperatures leads to quenching and increased CO emissions.
- High methane content could be due to:
  - Characteristics of some gas fields (particularly biogenic sources)
  - LNG import and use of LNG Boil-Off Gas (BOG)
  - Biomethane entry to grid

Mitigation Measures

Mitigation Measures

- Combustion system redesign:
    - Has effectively eliminated most flashback issues
    - Improvements in stability, emissions and dynamics

- Measurement of fuel composition and compensation through GT control
    - Issues with speed of composition measurement

- Measurement of Wobbe Index and compensation through fuel heating

- Control system response to changes in gas turbine behaviour without fuel composition or property measurement

Fuel Heating for Wobbe Index Control

- Increasing fuel temperature decreases the effective Wobbe Index of the fuel

$$WI = \frac{Calorific\ Value\ (volumetric)}{\sqrt{Relative\ density}}$$

- Calculate WI from measured fuel composition (slow) or use fast WI meter
- Change fuel pre-heat to compensate
- Very effective in controlling many emissions and dynamics issues
- Does not help with part load CO issues caused by low C2+ content
- Relatively low cost (especially if fuel pre-heat already implemented for efficiency improvement)

System response to changes in behaviour

- Most OEMs and some 3rd party suppliers have developed and are continuing to refine automatic tuning systems as discussed in "Dealing with Power Generation Gas Turbine Combustor Thermoacoustics"
- Siemens Advances Stability Margin Controller (aSMC)
  - Uses closed loop control of the combustion acoustics to change the pilot gas amount or the turbine outlet temperature according to a fixed set of set rules which depend of the load range and the frequency of humming
- General Electric OpFlex AutoTune
  - Automates combustion tuning
  - Optimises combustion dynamics and emissions using a model based control system
  - Self teaching algorithms are used and require initial set-up and tuning to generate robust models

Future Challenges:
Unconventional Gases:

- Shale Gas
- Landfill Gas
- Bio-Methane
- Gasification
- …etc.

Any Real Difference Between "Natural Gases"

- All predominantly methane
- Other alkanes in decreasing amounts: Ethane, Propane, Butane, Pentane...
- Varying amounts of sulphur compounds (particularly H_2S)
- Low levels of particulates containing trace components (alkali and heavy metals etc.)
- Varying amounts of inerts (CO_2 and N_2)
- New sources may have new minor constituents:
    - e.g. siloxanes in biogas from landfill and anaerobic digestion
    - SNG will have residual H_2 and CO and varying levels of higher hydrocarbons, tars, aromatics and particulates depending on gas treatment and cleaning
    - P2G+ methanation will have residual hydrogen and the potential for minor constituents depending on the CO_2 source

- No real difference between "Conventional" natural gas and new sources
    - Probably as much variation within "conventional" as there is between conventional and non-conventional
        - BUT greater variety of fuel sources will increase fuel variability
    - New sources may give unexpected problems due to new minor constituents

New Fuel Sources: Unexpected Contaminants

- Landfill and anaerobic digester gas would not at first sight present particular issues, BUT:
  - Siloxanes (volatile silicon compounds) are present in landfill gas and wastewater treatment digester gas in concentrations of the order of 10 ppmv

Siloxanes are converted to silica (SiO_2) in the flame. This may:

- Erode parts exposed to high velocity gas streams
- Form on blades and vanes as a powder or glass-like coating
  - leading to a reduction in turbine efficiency
  - possible blockage of blade and vane cooling holes
  - Adverse effect on refurbishability of the blades and vanes
- Possible fouling of downstream components
  - Loss of effectiveness of emissions control catalysts
  - Reduction in heat transfer efficiency in HRSGs

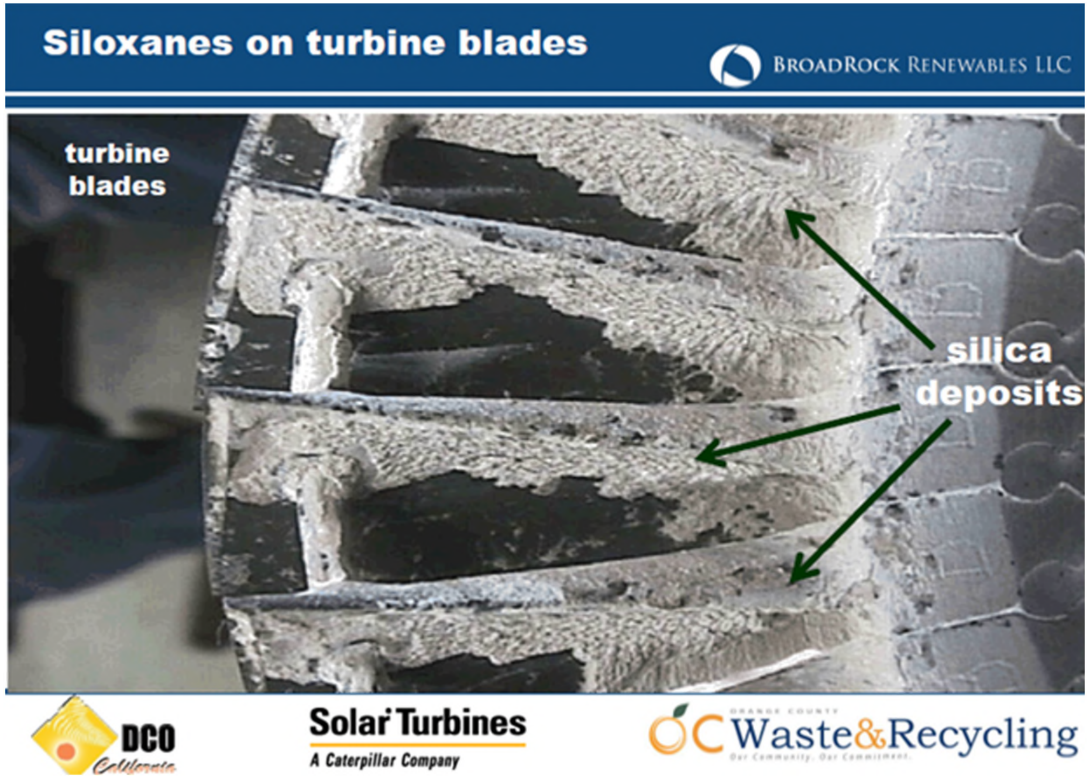


Image from presentation: 32 MW COMBINED CYCLE TURBINE PLANT AT THE OLINDA - ALPHA LANDFILL, UNIQUE TECHNICAL CHALLENGES, downloaded (29/08/22) from: https://www.epa.gov/sites/production/files/2016-05/documents/12_galowitzco_presentation.pdf

Future Challenges: Hydrogen-Containing Gases

Combustion of Hydrogen-Containing Gases

Potential for firing natural gas—hydrogen mixtures:

- Power to Gas (P2G)
  - Use of excess renewable electricity to produce hydrogen as an energy storage medium
- The hydrogen economy
- Co-firing of H_2 containing waste gases

Colours of Hydrogen

Green: water electrolysis using renewable electricity

Blue: from fossil fuel with CO_2 capture or use (CCSU)

Turquoise: methane pyrolysis producing solid carbon.

Purple: nuclear power and heat through combined chemo-thermal electrolysis of water.

Pink: water electrolysis using electricity from a nuclear power

Red: high-temperature catalytic splitting of water using nuclear power thermal energy

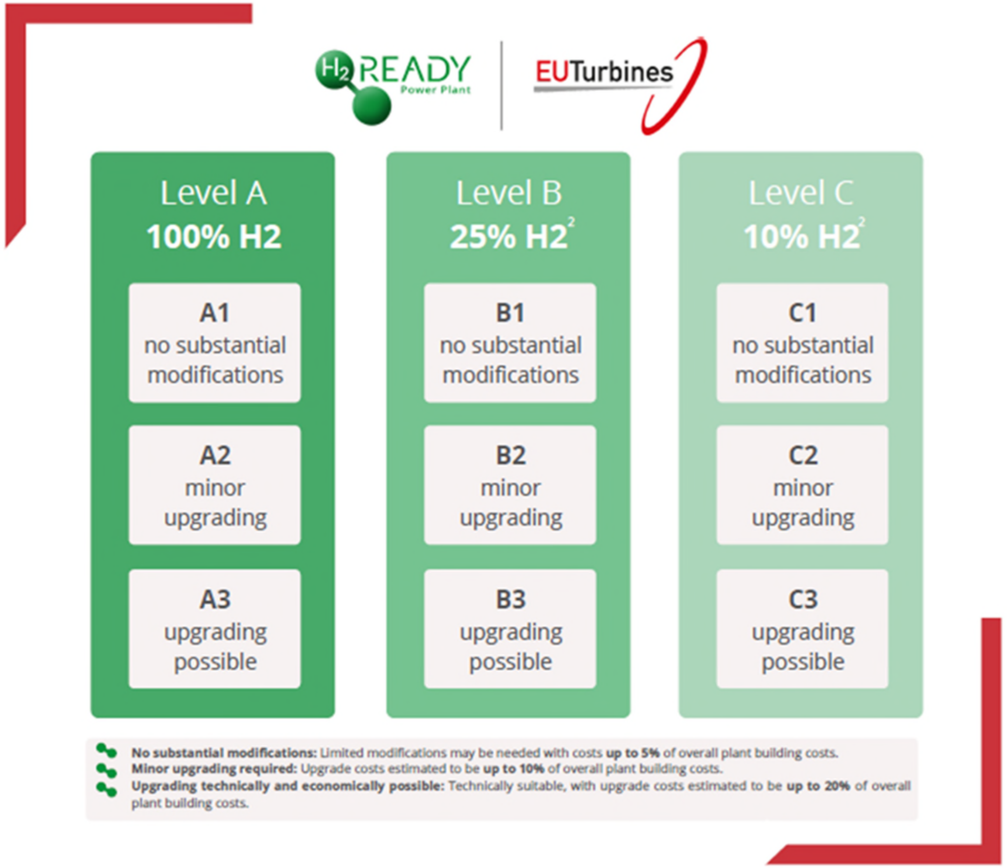
Gray/Black/Brown: From fossil fuel no CO_2 capture

Hydrogen in the natural gas grid: Manufacturers' View

Extract from EUTurbines document: H2-Readiness of Turbine Based Power Plants – A Common Definition

Hydrogen will remain a scarce resource over the next decade. It is likely that hydrogen valleys and hydrogen-dedicated pipelines are built in Europe within the near future but, especially in the distribution grid, the blending of certain levels of hydrogen into the natural gas pipeline will be a valuable option in the transition. The maximum blending share is expected to remain limited to around 25% by volume – above that level there will most likely be a switch to pure hydrogen in one step. By 2050, that switch should be fully concluded.

https://www.euturbines.eu/wp-content/uploads/2021/09/EUTurbines-H2-ready-Definition-September-2021-1.pdf



EUTurbines Members: Ansaldo Energia, Baker Hughes, Doosan Skoda Power, GE Power, MAN Energy Solutions, Mitsubishi Power Europe, Siemens Energy and Solar Turbines.

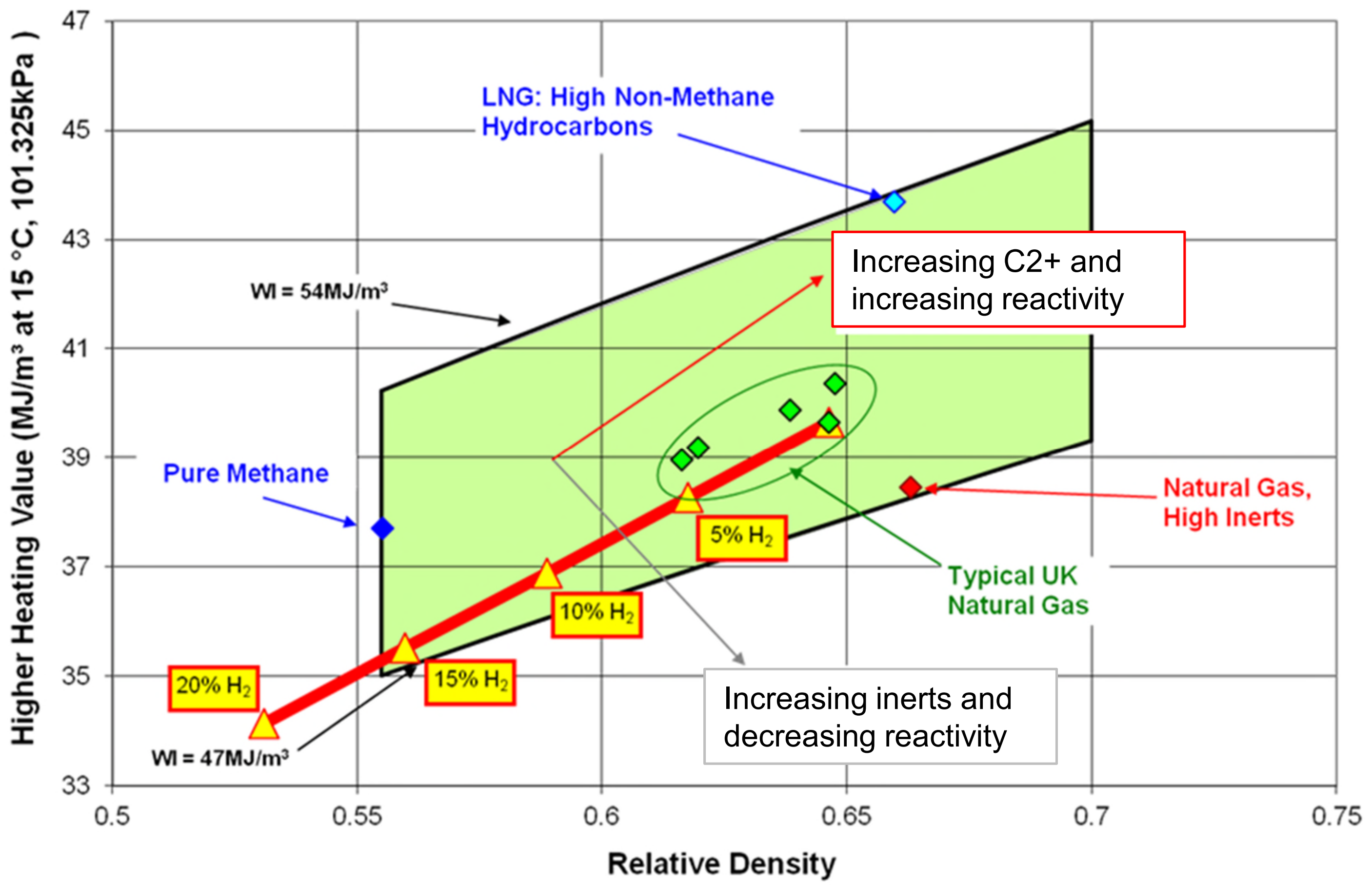
Combustion of Hydrogen-Containing Gases

- Diffusion systems tolerate up to 100vol% H_2, but with high NO_X emissions or control using diluents (e.g. water, steam or nitrogen)

- Lean premix specifications historically range from “trace” to 20vol%+, but manufacturers are extending the allowable range
- Typically might expect 1-5vol% to be feasible for most of the existing fleet: some capable of more
- Manufacturers all developing options for higher hydrogen contents for new and retrofit applications

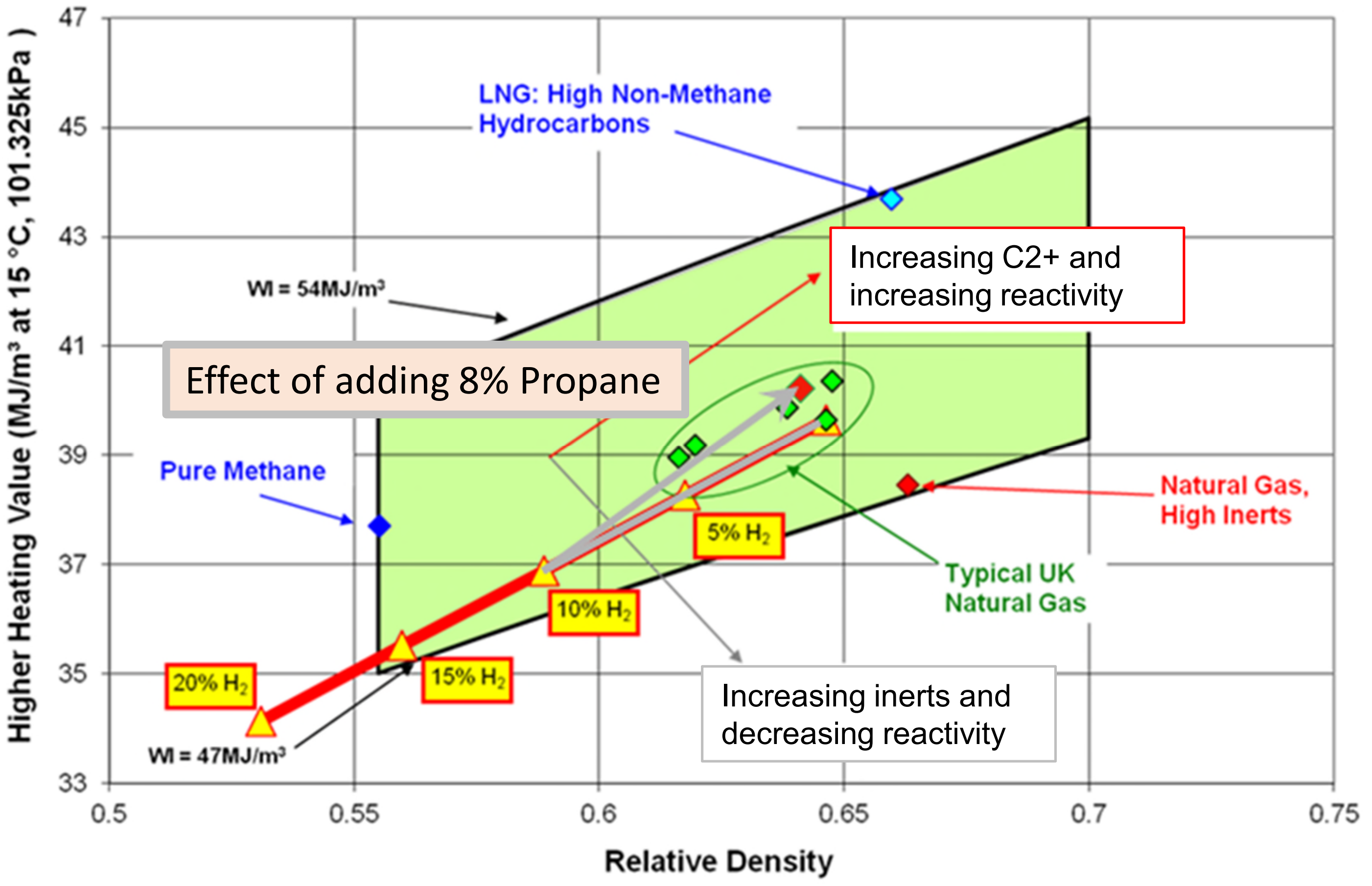
Effect of Hydrogen Addition on Typical Natural Gas

- HHV/WI plot often used to compare natural gases
- Hydrogen addition reduces RD and WI



Effect of Hydrogen Addition on Typical Natural Gas

- Adding 10% hydrogen, then 8% propane results in a similar position on plot
- BUT the mixture is much more reactive impacting:
    - Flashback risk
    - Flame shape and position
    - Combustion dynamics
    - Emissions



Some Key GT Concerns for Hydrogen-Containing Gases

- Affects emissions, dynamics and flame stability (flash-back)
  - Impact on operability, reliability, availability, component life, costs
- Increased risk of exhaust explosion potential
  - GTs firing high H_2 fuels (>5vol%) typically start on alternative fuel
    - Increased flammability giving exhaust explosion risk and possibly flashback
- Impact on Hazardous Area Classification
- Increased leakage potential (internal and external)
  - Hydrogen is an indirect greenhouse gas
- Many current gas detectors do not recognise H_2
- Impact on WI/RD masks increasing reactivity

Properties of Hydrogen and Methane

- Lower volumetric CV means over 3x the volume of hydrogen need for same energy input
  - Affects supply system capacity
  - Changes momentum of fuel jets, affecting fuel placement and mixing
- Higher maximum adiabatic flame temperature
  - Potential impact on NOx
- Laminar flame speed of hydrogen ~8x that of methane
  - Indicator of increased reactivity
  - Increases flashback risk
  - Leads to more compact flames

	Hydrogen	Methane
Relative Density (-)	0.07	0.55
Lower Calorific Value (MJ/kg)	119.93	50.02
Lower Calorific Value (MJ/m^3)	10.05	33.36
Flamability Limits in air (% by volume)	4 to 75	5.3 to 15
Minimum ignition energy in air (mJ)	0.02	0.29
Autoignition Temperature (K)	858	813
Maximum adiabatic flame temperature in air (K) (air at 20°C and 101.325kPa)	2376	2223
Maximum laminar flame speed in air (cm/s) (air at 20°C and 101.325kPa)	306	37.6

Impact of hydrogen on emissions corrections

Combustion of 1 mole of methane:

- $CH_4 + M(air) \rightarrow CO_2 + 2H_2O + M(air) - 2O_2 + XNO_X$

Combustion of R moles of hydrogen will have same thermal energy as 1 mole of methane if:

- $R = LCV(CH_4)/LCV(H_2) = 3.3194$
- $RH_2 + M(air) \rightarrow RH_2O + M(air) - RO_2/2 + XNO_X$

- NOx emissions corrected to 15%O_2, dry, results in emissions levels for hydrogen being 36.4% higher than for methane when the same number of moles of NOx are produced per unit of energy input

Combustion product compositions (assuming X is small)

	CH_4	H_2
Moles of products (wet)	M+1	M+R/2
Moles H_2O in product	2	R
Moles of products (dry)	M-1	M-R/2
Moles O_2 in products	0.2089M-2	0.2089M-R/2
Moles of NOx in Products	X	X

$$\frac{C_{H2}}{C_{CH4}} = \underbrace{\frac{\left[1 - \frac{2}{(M+1)}\right]}{\left[1 - \frac{R}{\left(M + {R}/{2}\right)}\right]}}_{\text{Ratio of wet to dry corrections}} \underbrace{\frac{\left[0.21 - \frac{(0.2089M - 2)}{(M-1)}\right]}{\left[0.21 - \frac{\left(0.2089M - {R}/{2}\right)}{\left(M - {R}/{2}\right)}\right]}}_{\text{Ratio of oxygen corrections}} \underbrace{\left[\frac{(M+1)}{\left(M + {R}/{2}\right)}\right]}_{\text{Hydrogen correction for raw concentration}}$$

$$\frac{C_{H2}}{C_{CH4}} = \frac{4.5281}{R} = 1.364$$

Question?

Is there any fundamental reason why a well-optimised hydrogen flame should produce more NOx than a natural gas flame with the same flame temperature?

- Typically NOx from gas turbines burning natural gas is produced by the thermal route and is thus dependent on peak flame temperature
- If this is true for hydrogen combustion and kinetics are similar, NOx levels should be similar

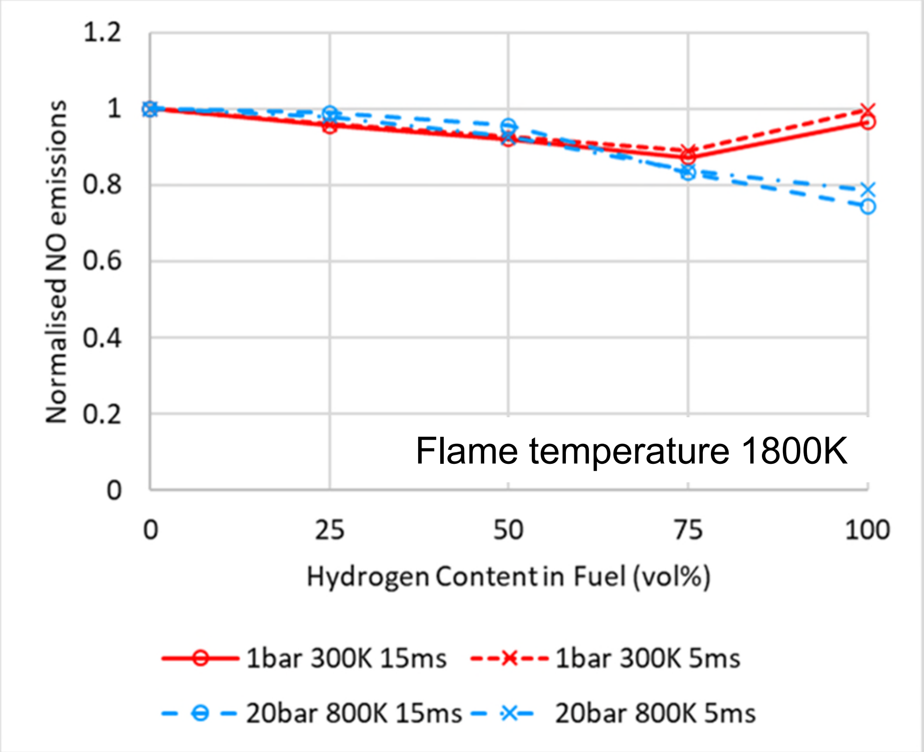
Impact of Hydrogen on NOx Emissions: Theoretical

- Kinetic calculations for ideal premixed flames suggest that (depending on conditions) adding hydrogen to natural gas could result in lower NOx emissions
- Another study suggests that at lower flame temperatures there may be a small increase

BUT

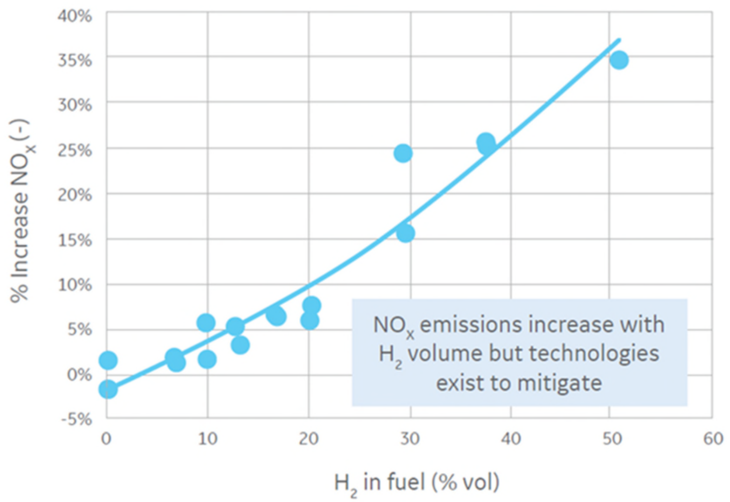
- Tests on practical gas turbine burners show significant increases in NOx

NOx emissions for an ideal premixed flame (on a mass/energy input basis)



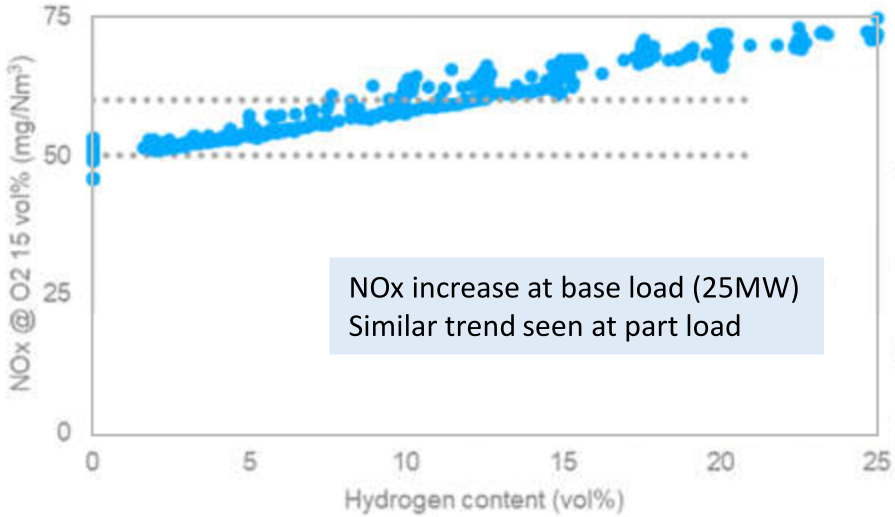
Re-plotted using data in Breer et al, NOx Production from Hydrogen-Methane Blends, Spring Technical Meeting, Eastern States Section of the Combustion Institute, March 6-9, 2022, Orlando, Florida.

Impact of Hydrogen on NOx Emissions: Theoretical



- Based on rig data GE suggest that at 50vol% hydrogen NOx emissions would be ~35% greater than natural gas
- Extrapolating to100%, NOx emissions could double

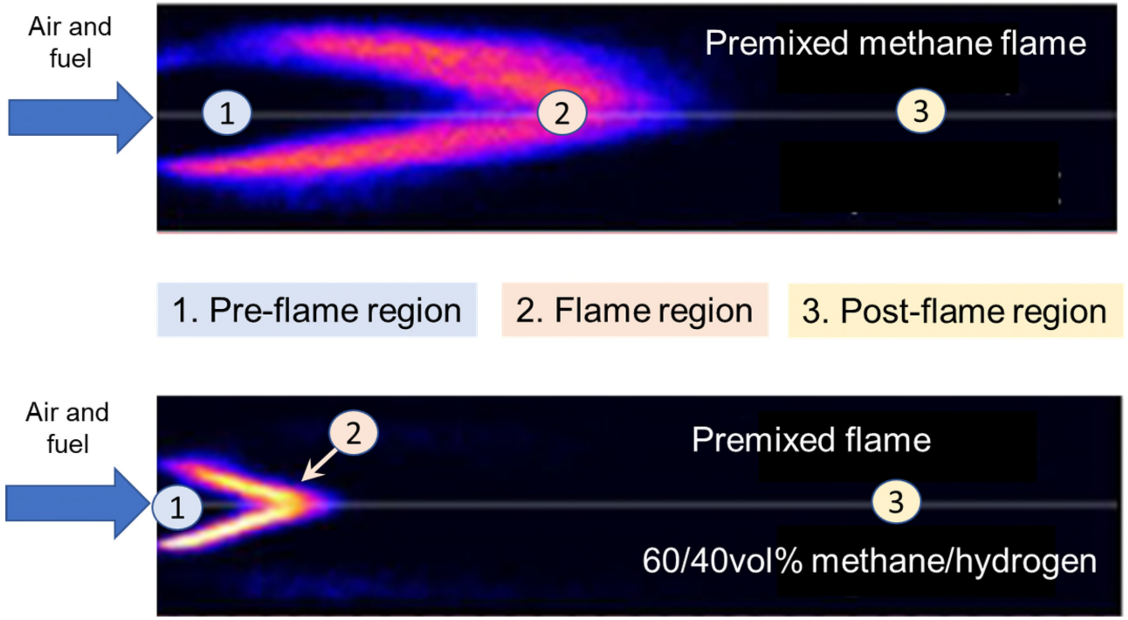
From: Hydrogen for power generation: Experience, requirements, and implications for use in gas turbines , GE document GEA34850



- On-engine tests on a Siemens SGT-800 showed even greater increases in NOx:
  - 50% increase at 25vol% hydrogen
- Re-tuning could recover some of the increase

Modified from: Laget et al, DEMONSTRATION OF NATURAL GAS AND HYDROGEN CO-COMBUSTION IN AN INDUSTRIAL GAS TURBINE, Proceedings of ASME Turbo Expo 2022, Turbomachinery Technical Conference and Exposition, GT2022, 2022, Rotterdam, Paper: GT2022-80924

Why is NOx greater for a practical combustor?



- In a premixed flame, NOx depends on:
  - Flame location
  - Unmixedness of air fuel at flame front
  - Flame residence time
  - Post flame residence time
- Adding hydrogen:
  - Affects fuel/air momentum and thus fuel placement and mixing
  - Higher reactivity moves flame upstream, reducing mixing time and increasing unmixedness
  - Higher reactivity reduces flame residence time which could reduce NOx generation within the flame
  - Post flame residence time increases, negating benefit of lower flame residence time

Flame images from: Muppala et al, COMPARATIVE STUDY OF DIFFERENT REACTION MODELS FOR TURBULENT METHANE/HYDROGEN/AIR COMBUSTION, Journal of Thermal Engineering, Volume 1, Issue 5, Pages 367 - 3801, February 2015

Reactivity, Flame Speed and Flashback

- Hydrogen increases reactivity in a similar way to C2+ and flashback risk is a significant concern for hydrogen blends
- In practical GT combustors flow is turbulent
- Turbulent flame speed is related to laminar flame speed, but measurements show greater impact of hydrogen on turbulent flame speed
  - Kinetics is not the only impact
  - Other properties such as diffusivity also have an impact

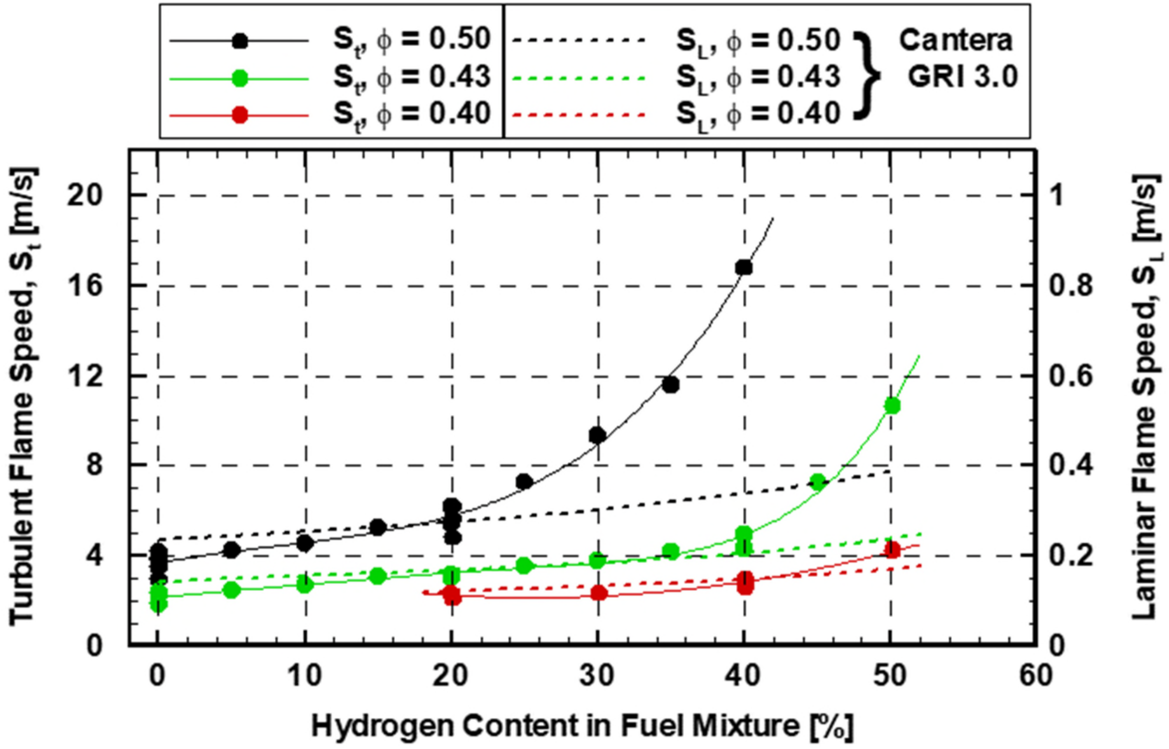


Figure from: Boschek et al, FUEL VARIABILITY EFFECTS ON TURBULENT, LEAN PREMIXED FLAMES AT HIGH PRESSURES, Proceedings of GT2007, ASME Turbo Expo 2007, Paper GT2007-27496

Combustion technologies for hydrogen

Conventional or diffusion combustor

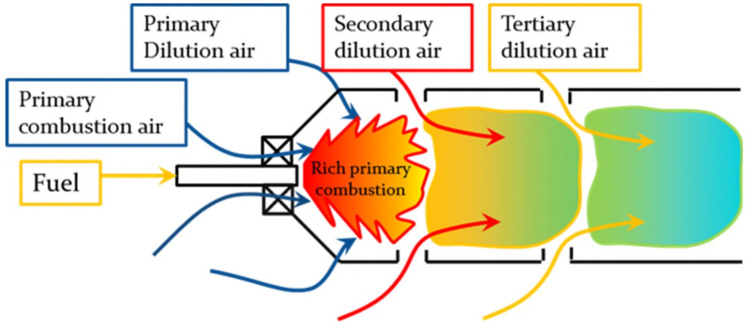
- Robust, stable and fuel flexible: capable of burning high hydrogen fuels
- High NOx unless diluent injection such as water or steam is used
- Main technology offered today for 100% hydrogen combustion.

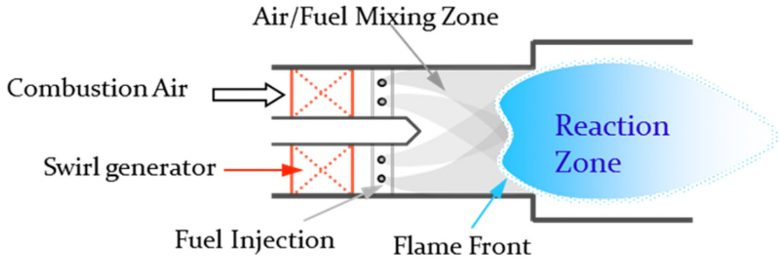
Lean premixed combustors

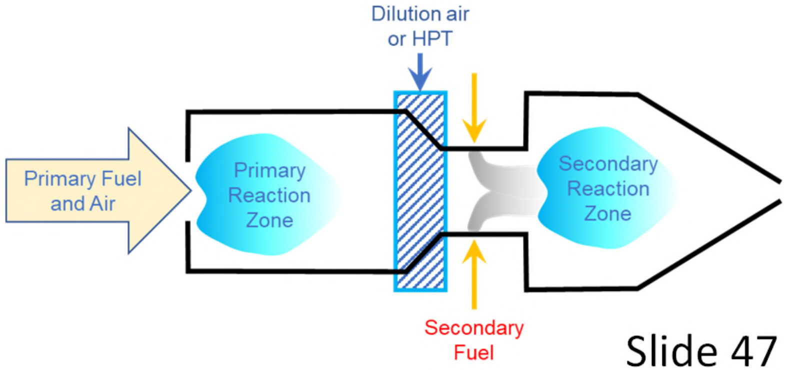
- Dominant technology for natural gas combustion.
- Low NOx firing natural gas
- Issues with thermoacoustics
- Flashback risk with high reactivity fuels such as hydrogen
- Allowable hydrogen concentration depends on design details
- Unlikely that current systems can fire high hydrogen concentrations without re-design.

Sequential combustion

- Different fuel stages arranged axially
- Used to reduce initial flame temperature to reduce NOx improves fuel flexibility





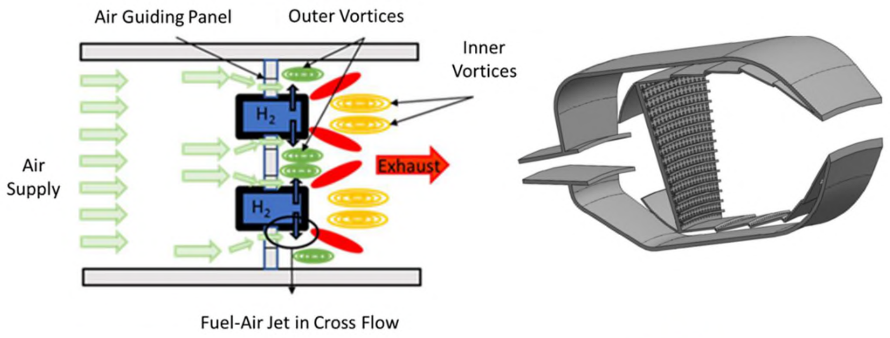


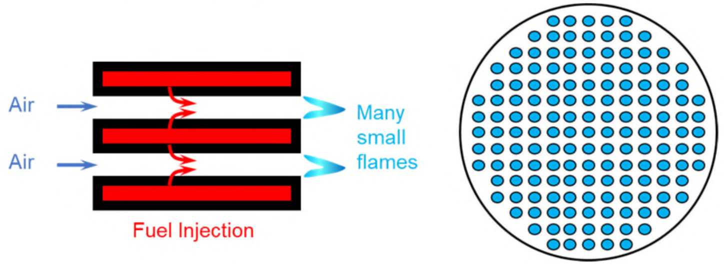
Combustion technologies for hydrogen

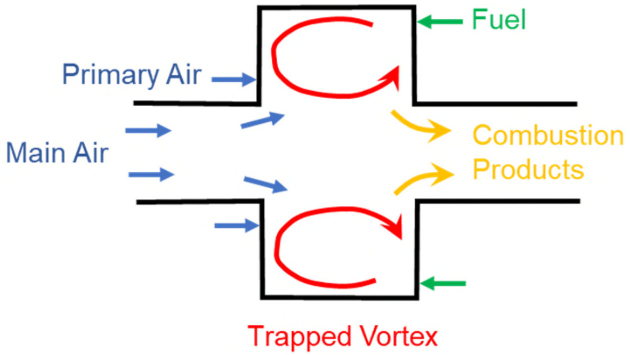
Micro-injection combustors
- Many small flames
- Low NOx due to the short residence
- Diffusion-based and premixed-based concepts are under development
- The term “micromix” sometimes used to refer to both concepts

MILD combustion or Flameless oxidation
- Uses highly diluted oxygen depleted oxidiser instead of air
- Reactant temperature high, peak flame temperature relatively modest
- Leads to low NOx formation
- Dilution and oxygen depletion achieved in a number of ways including exhaust gas recirculation and humid air cycles

Trapped vortex combustors
- Utilises a vortex typically trapped within a cavity
- Fuel is injected into the trapped vortex
- Efficient and rapid mixing of reactants and recirculated combustion products
- Combustion conditions typical of flameless oxidation







Conclusions

- Variations in fuel composition (even within grid and OEM specifications) can cause significant problems for gas turbine operators
- In recent years OEMs have developed more robust systems, automatic tuning systems and other mitigation measures
- However, cost of upgrades and implementation of mitigation measures remains an issue in the competitive power generation market
- Future challenges
  - Operational flexibility due to high levels of renewable energy
  - Hydrogen addition to the gas network
  - 100% hydrogen combustion
  - New fuel sources and increased gas trading/import
    - Leading to increased fuel variability

Power generation gas turbines will have to be increasing flexible both in terms of operating schedule and fuel composition.

Thank you for your attention

Any Questions?

Dr David Abbott

d.abbott@cranfield.ac.uk