NATURAL GAS UTILISATION IN ELECTRICITY GENERATION - SPECIAL TECHNICAL CONSIDERATIONS AND OPERATIONAL ASPECTS.

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Alternative natural gas-burning plant arrangements are compared, having regard to the gas supply contract and the integration of the plant into an existing system. The importance of safety and environmental considerations is emphasised.

INTRODUCTION

The background to this paper is the discovery of a viable gas field off the South coast of Ireland and the allocation of a quantity of this gas to the Electricity Supply Board. An attempt is made to identify and assess specific technical considerations involved in the introduction and integration of gas-burning plant into an existing system.

CHOICE OF PLANT

The choice of power plant to utilise natural gas fuel is very wide and depends on gas contract limitations in terms of form and supply, gas quality and the matching of various plant configurations to these limitations. It will also depend on economic considerations such as the capital cost of different types of plant and their running costs. Figure 1 gives an outline of the various types of plant already used to generate electricity from natural gas.

Gas Contract.

The gas contract will optimally be negotiated with certain plant configurations in mind as regards minimum flows, maximum pressure and limitations on rate of change of gas flow. However, if the supply is interruptable, plant power output flexibility and security can only be maintained by the adoption of a dual-fired system with its associated fuel storage and handling facilities. A "pay or take" clause in the contract needs careful scrutiny in the light of plant availability and proposed maintenance schedules. For instance, if the annual contracted period is 365 days per year, gas burning plant must be capable of consuming more than the average daily contracted gas flow. In the above context a guaranteed gas supply peaking facility written into the contract and provision for "carry over" of unconsumed gas quantities below the contracted annual amount from one year provides greater operational flexibility.

The gas contract will include a gas quality clause covering the physical properties of the gas supplied in terms of sulphur content, impurities, dust, water and hydrocarbon dewpoints and calorific value. It is important that the contract allow for the worst conditions during the expected lifetime of the gas burning plant. This quality clause is all the more important if the gas is expected to come from different reservoirs.

Different gas-turbine manufacturers can specify different fuel specifications and this must be taken into consideration in the gas contract quality specification. In contrast, however, all gas-turbine manufacturers are unanimous

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in specifying that the gas must not contain any liquid hydrocarbons at the inlet to the fuel system.

Choosing Gas-Burning Plant.

The main choice of plant type lies between the conventional boiler and steam turbine and the combined cycle-type plant. There is also the further choice of buying new plant, converting existing plant or some combination of both. For instance, a gas turbine might be repowered with a new waste-heat boiler and a new/existing steam turbine or a conventional boiler could be converted to gas/dual firing, (Fig. 1.). The final decision will depend on the particular circumstances regarding the type of gas supply, the availability of suitable convertible plant, required plant load factor and flexibility criteria.

Dual Fuel or Single Fuel.

The advantages of using natural gas in a single fuelled situation range from the lower stack temperature possible to the increased intervals between maintenance outages. Back-up facilities in terms of secondary fuel storage and handling do not exist (except for a limited amount of emergency fuel). Maintenance requirements will be known with greater accuracy as compared to an intermediate dual-fuel situation where running time is divided between the two fuels. For example, in the case of gas turbines the use of distillate oil fuel decreases the intervals between maintenance (Wilson (1)):

TABLE 1 - Maintenance Factor.

	Natural Gas	Distillate
Maintenance Factor	1	1.3

In the case of an interruptable gas supply, it is necessary to have dual-fired plant, gas/oil/coal for conventional boilers and gas/diesel for gas turbine or combined cycle plant. There are a number of disadvantages associated with dual-fuel firing as compared to the single fuel feed-stock - (1) the need for added storage and fuel handling facilities; (2) the complexity of control equipment required to enable safe and efficient change-overs from one fuel to the other; (3) the loss of the lower stack gas temperature advantage since the alternative fuel to natural gas will have amounts of sulphur present; (4) the need for chimney heights to be adequate for the fuels more demanding than natural gas.

New or Converted Plant.

For plant conversion, there is the dilemma of whether to modify existing fuel-burning equipment or to scrap existing facilities and instal new natural gas or dual fuel burners. The former type of conversion will require the interfacing of two different types of control systems.

Safety regulations for natural gas firing will require the resiting or flame proofing of any existing electrical equipment within certain risk areas. The problem of shortage of space can occur in enclosed boiler houses with the introduction of natural gas piping, control points and the like. Older plant operating on pulverised fuel or residual oil may have developed a coating of acid bearing ash/scale in the precipitators and flue gas stacks, requiring a refurbishment of these units with acid resisting mortar for the high water dew-point flue gas associated with natural gas. Table 2 below confirms the opinion that acidic ash build-up behind cone liners is most probable where seals have failed - particularly near the chimney top where temperatures are lower (Hanson (2)).

For a discussion of dual-fired boiler heating surface requirements, see Stern and Godridge (3).

Combined Cycle Plant.

The flexibility and high efficiencies (predicted target efficiency = 55-60% (4) possible with natural gas-fired combined cycles have received much attention in recent times. Where proven technology is a consideration, it could be argued that the higher rated units are still at the development stage and that operating experience to date is relatively limited.

TABLE 2 - Acid and Water Dew Points.*

O_2 I.D. Fan Outlet	SO_3 P.P.M. I.D. Fan		Acid Dew Point (°C)		Water Vapour Dew Point (°C)	
	Oil	Gas	Oil	Gas	Oil	Gas
2.0	8.0	0.0	127.7	-	47.5	58.2
3.0	8.0	0.0	127.1	-	46.5	57.0
5.0	12.0	0.0	129.9	-	44.4	55.1
7.0	12.0	0.0	128.7	-	42.4	53.1
9.0	12.0	0.0	127.3	-	40.0	50.1

* Ambient Air Humidity taken at 6g Water/Kg dry air.

It is possible to synchronise the installation of combined cycle gas burning plant in terms of power potential with the development of a new gas well and to have the ability to respond quickly to subsequent reservoir appreciation. It is useful to draw up a history of installed plant capabilities and compare these to contracted annual gas flows during the well flow build-up period.

BOILER HOUSE ENVIRONMENTAL SAFETY

It is proposed to concentrate on the boiler house environment only as combustion safety considerations are adequately dealt with elsewhere (Snell and Cresswell (5), Zanchi (6), Hancock and Spittle (7). Boev (8)). In this context, the following table showing the percentage of explosions in boilers fired by natural gas in the U.S.A., occurring between the years 1947-1958 is of interest (3):

TABLE 3 - Accident Records.

		%
(1)	Disappearance of flame because of accumulation of liquid or inert gas in the pipeline.	23
(2)	Insufficient ventilation before lighting up.	18
(3)	Human Error.	11
(4)	Malfunctioning of Controls.	11
(5)	Leakage of Valves	5
(6)	Incorrect adjustment of air/gas flows.	5
(7)	Faulty Gas supply system.	5
(8)	Ignition burner.	4
(9)	Fans and Registers.	4
(10)	Unknown.	14
		100%

In the absence of a Code of Practice referring specifically to gas burning installations, reference is made to the following codes - "Supplement to the 1965 Institute of Petroleum Code of Safe Practice", B.S.C.P. 1003 Part 3 and B.S. 4137 of 1967.

Natural gas is classified under lighter-than-air gases i.e. gases whose density is less than 75 per cent of the density of air at standard conditions (9). Gas-air mixture explosive limits are indicated in Fig. 2.

To determine the type of electrical installation appropriate to a gas-fired boiler zone, it is necessary to classify areas according to the degree of probability of the presence of a dangerous atmosphere. C.P. 1003 recognises three sets of conditions:

Div. 0 - An area or enclosed space within which any flammable or explosive substance, whether gas, vapour or volatile liquid is continuously present in concentration within the lower and upper limits of flammability.

Div. 1 - An area within which any flammable or explosive substance, whether gas, vapour or volatile liquid is processed, handled or stored, and where during normal operations an explosive or ignitable concentration is likely to occur in sufficient quantity to produce a hazard.

Div. 2 - An area within which any flammable or explosive substance, whether gas, vapour or volatile liquid, although processed or stored, is so well under conditions of control that the production (or release) of an explosive or ignitable concentration in sufficient quantity to constitute a hazard is only likely under abnormal conditions.

According to the B.S. CP 1003 classification system gas-fired boiler houses fall within dangerous area Division 2 by meeting the following criteria:

(a) Fire or explosion is only possible in the improbable case of a spark and a dangerous atmosphere occurring simultaneously in the same place. This criterion applies since natural gas is not spontaneously combustible in air at the pipework, ducting or boiler cladding temperatures.

(b) A dangerous atmosphere due to a gas leak can only be caused by a pipework, valve and/or control failure. This criterion applies except for the unlikely case during burner proving where ignition is unsuccessful and gas escapes through boiler inspection doors. These doors will normally be closed and furnace pressure levels will be below atmospheric.

(c) The area is well ventilated to remove any dangerous atmosphere. This criterion is covered by the natural air circulation in the boiler house and also by the action of the forced draught fans where inlet air is taken from the top of the boiler house and thus promotes forced ventilation.

(d) A spark or arc can only be caused by electrical equipment. This criterion is met where all electrical wiring and equipment complies with Division 2 regulation. It also requires that all equipment should be earthed.

(e) There are no unventilated spaces in which gas can collect in pockets. This requirement is met if such places (e.g. roof) where gas could collect are ventilated.

It is particularly emphasised that the area classification of safe distances recommended are based on plant being installed in locations where there is adequate ventilation; if a plant is installed in "open premises" it is important that the ventilation system is such that the dispersal of gases would approximate to the conditions on a plant in open air.

The concept of area classification is a comparatively recent concept. Until the 1960s, with a few exceptions, areas were regarded as either safe or dangerous and in the danger areas only flameproof and intrinsically safe apparatus was used. This approach, which stemmed from coal mining techniques and was quite practical for small simple industrial plant, was found to be altogether too rigid and uneconomic for the large oil and chemical complexes for which area classification was introduced. Just as the earlier "flameproof-or-nothing" approach stemmed from mining practice, so the latter area classification approach was borrowed from the oil-well drilling fields. In both mining coal and drilling for oil there is the ever present risk of breakthrough to unknown and uncontrolled reservoirs of flammable gas, with the high probability that gas/air concentrations within the explosive range will then persist for prolonged periods in large areas at the coal face or around the drilling rig. Thus situations within a mine or at a drilling rig are very different indeed from those in properly designed and engineered industrial plant. In industry the release of flammable liquid or gas can and should be restricted to small quantity spillage, leakage and venting in all normal operations, and only on the occurrence of disaster situations of gross plant failure should there be any possibility of uncontrolled discharge or large volumes (Arnaud (10)). Experience of process plant in refineries associated with this type of gas indicates that releases in excess of 10 cubic feet per minute are considered unlikely and it has been shown experimentally that the probability of ignition is nil at a distance greater than 10 feet horisontally from the source. This suggests that the present techniques of industrial hazard area classification might well be replaced by what might be called the "risk point" approach. The basis of the "risk point" approach would be that in any area, whether indoors and enclosed or out-of-doors in the open, in which flammable gases or liquids are pumped and processed under pressure, the plant is so designed that the likelihood of the release of a large volume is limited to the plant failure disaster situation. But within the whole area there would be "risk points" wherever there are foreseeable sources of leakage, spillage and venting. Thus, throughout the area, electrical apparatus suitable for only "remotely dangerous (i.e. Division 2) areas" should be adequate everywhere except in the immediate vicinity of "risk points".

It has been suggested that the main categories of "risk points" which occur in industrial plant are:

A. Persistent.

Interiors of pressure vessels and pipes containing gas/air mixture.
Free spaces above liquid level in tanks.
Free spaces immediately above open dipping, etc. baths.
The immediate vicinity of vapour exhausts and liquid outlets where these are designed to discharge as part of normal plant function.

These are clearly Division 0 "risk points". They are also "risk points" at which there seems to be no foreseeable need for power electrical apparatus, for power can be transmitted mechanically from outside enclosed tanks or from a point removed from the immediate vicinity of a vent or free surface, and light can be projected. There can, however, be need for instrumentation and control at the "risk point" itself, (level, pressure, temperature, etc., transmitters) and this need can be, and is, provided for by the use of intrinsically safe circuits which do not have function sparking contacts in the circuit exposed at the point of risk.

B. Occasional.

The immediate vicinity of mechanical glands and other localised spillage and of vapour exhausts and liquid outlets designed to discharge only on plant malfunction (10).

These are the Division 1 "risk points" at which power electrical apparatus is involved and at which it is essential to consider the degree of protection afforded to industrial types of apparatus by the recognised methods of preventing electrical ignition.

On the basis of the foregoing, the adoption of "risk point" determination could not only considerably simplify the problem of the choice of electrical apparatus for use in potentially hazardous areas but it could also lead to an improvement in the overall achievement of safety from fire and explosion.

The strategic location and permanent installation of suitable pellistor or semi-conductor type gas detectors at "occasional" risk points and/or collection points (e.g. forced-draught fan inlet points) can provide continuous monitoring and give an early warning of incipient leaks. Specification of a stenching agent in the supply gas permits the safe tracing of leaks, with the use of a portable methanometer. Figure 3 gives details for dry chemical extinguishing requirements.

Figure 4 shows the extent of Division 2 areas where non-sparking apparatus only can be installed. In the case of natural gas-fired boilers the actual gas supply pipework is the "source of hazard".

REDUCING STATION

The revised version of DVGW Arbeitsblatt G491 "Technical regulations for construction and equipment of gas pressure control devices with an inlet pressure of more than $3kp/cm^2$", requires that two independent safety devices be provided when the following conditions prevail simultaneously:

$$P_1 \text{ max} - P_O \text{ max} > 15kp/cm^2 \text{ and } P_1 \text{ max}/P_O \text{ max} > 1.6$$

where P_1 max is the maximum operating pressure on the inlet side and P_O max is the maximum permissible pressure on the downstream side of the gas pressure control device, an emergency venting valve for the full capacity of the gas pressure control device being employed. As venting of a large gas volume can lead to environmental difficulties, an additional small emergency venting valve for leakage gas volumes can be employed (Minkner (11)). A high pressure gas leak exerts powerful forces and vents from high pressure lines must be well-anchored to prevent a "recoil" effect. The speed of closing of the slam shut or safety stop valves is critical and must be at least enough to control the downstream pressure rise. This depends on the nominal downstream pressure, the volume of the downstream pipework and the open cross section of the control valve. The following equation describes the outlet pressure profile under super-critical conditions:

$$P(t) = \frac{P_1}{\tau} + P_O \qquad (1)$$

where $P(t)$ = Downstream pressure after time (t).
P_o = Downstream pressure at time (O).
P_1 = Control valve inlet pressure.
and τ = $\frac{V}{M.F.} \cdot \delta$ = time constant.
where V = Volume of downstream pipework (cm^3).
M.F. = Maximum effective cross-section of gas pressure control device (cm^2).
δ = Gas co-efficient ($\simeq 0.42 \times 10^{-4}$ sec/cm for natural gas).

The optimum volume of piping downstream of the regulator station must be large enough to permit a stable change over to the standby system without disruption of the gas flow.

The gas must be heated at the inlet to the pressure reducing stages to allow for the Joule-Thompson effect. With a delivery pressure of 690kN/m^2 and a reduction to 345kN/m^2 (normal gas pressure supplied to boilers) a temperature drop of near 38°C might be expected. This condition could create several unacceptable mechanical and operational conditions e.g. erratic valve operation, methane hydrate scaling, condensation or frost-heave and damage to pipework due to metal embrittlement. Consequently gas temperatures have to be elevated prior to expansion to compensate for this temperature drop.

Installed plant for heating purposes is either hot-water boilers circulating water through heat exchangers or water-bath heaters, where the gas passes through heat exchange pipework within the boiler shell (Moody (12)). As gas pressure will normally be higher than the water in heating circuit. special safety cut-off valves at the heat exchanger gas inlet and outlet must be provided in case of gas leaks. The maximum permissible gas temperature after reduction will depend on the internal coating used in pipework, the type of material used in the silencers, and pipework design. The terminal gas temperature difference at the heater should not exceed 30-40°C.

NOISE

The high pressure gas supply pipelines normally extend to the power station boundary. In most cases, it is necessary to build a gas regulating station - with effective noise control - to provide the desired gas operating pressures.

Unfortunately, reducing valves can generate noise at frequencies between 30 and 7000 Hz and are usually responsible for nearly all the noise generally blamed on piping systems. Flow noise in pipes, vents and piping discontinuities - other than valves - is usually negligible by comparison. It should be noted that noise generated by pipe bends cannot be reduced by the use of flow straighteners as they normally suffer from aerodynamically generated forces of drag and lift due to gas flow and can radiate as sources of dipole noise. Once introduced into the piping system, valve noise can persist for long distances. An understanding of regulator noise generation is therefore essential if proper noise control is to be effected.

The inner valve of a regulator, located directly in the main flow and necessarily somewhat loosely guided, is subject to any and several of the following conditions:

: Vertical vibration : Natural resonant frequency
: Horizontal vibration : Aerodynamic noise

Vertical vibration of the valve at 30 to 60Hz can be a common source of rumble. (See Table 4 indicating different noise sounds versus frequency.) It is precipitated by changing dynamic forces which tend to open the valve at some points and to close the valve at others.

TABLE 4 - Noise Sounds versus Frequency.

Frequency Band (Hz)	Description
30 - 60	Rumble
400 - 1500	Howl
1500 - 4000	Hish
3000 - 8000	Squeal
20,000 and Higher	Ultrasonic

Horizontal vibration in which the inner valve may strike its guides at 400 to 1500 per second can create a howling sound.

If the vibration induced by pulsation of the fluid passing through the valve approaches the natural frequency of the plug-stem combination we have a resonance situation which can be identified by a high pitched noise at 3000 or even 6000Hz.

This noise can be detrimental not only from a nuisance standpoint but also because of the fatigue it can cause in regulator parts (Mahns (13)).

Noise resulting from mechanical vibration as described. has, for the most part, been eliminated by improved valve design and is generally considered a structural problem. Most of the noise generated in regulators stems from the high velocities at which gas passes through the valve parts. This is aerodynamic noise and manifests itself in a hishing sound between 1000 and 4000Hz. It is a by-product of the reconversion of the kinetic energy through turbulence into heat downstream of the throttling orifice. There are two basic contributing factors. One is the terminating shock front of a supersonic jet emanating from the vena contracta of the valve orifice (at higher than critical pressure drop). The second comes from the general turbulence of the fluid boundary and is apparent above, as well as below, choked flow in the valve orifice (Brauman (14)).

Unfortunately, there are no simple ways of completely avoiding aerodynamic noise since a way of reducing pressure without causing some turbulence has yet to be invented.

Standard valves are always noisy in choked service for any substantial flow rate and the solution rarely lies in selection from standard designs. because all are variations on the orifice, obtaining brute-force pressure reduction through sudden contraction and expansion losses. Effective noise control is achieved only by substituting valves of special design that change the physics of the internal flow, or by treatment of the transmission path.

Figure 5 shows a comparison between a standard valve and a low noise level valve design (Seebold (15)).

Improvements can also be affected by the introduction of additional stages of pressure reduction. To avoid multiplying the number of valves, orifice plates can be used to obtain small pressure reductions in conjunction with a single valve. The plates are normally installed in expanders whose increasing flow areas match the given pressure level and keep the velocity gradient through the whole system nearly constant. Silencers are effectively used to aid the aero-dynamic treatment. Heavy-walled pipe and external acoustical insulation are effective only for localised noise reduction. They do not reduce the noise in the fluid stream, but only shroud it where the treatment is used. Consequently, much of the noise is carried downstream, and at times upstream as well, depending on the application, only to reappear at a point where the treatment is discontinued (French (16)).

A good silencer on the downstream side of a regulator can provide from 18db to 22db attenuation in the pipe run downstream of the silencer. A silencer on the upstream side of a regulator can provide from 12db to 15db attenuation in the upstream run.

The most important element in absorptive silencers is the acoustic absorbing material. Natural fibre felts, such as wool and hair, are suitable in the case of natural gas, as temperatures are low and the gas is neither wet nor corrosive. The second most important element is the perforated metal used to retain the acoustic pack. No more than 50 per cent of the acoustic surface need be exposed and even as little as 15 per cent exposure is quite adequate (Duerr (17)).

To assure better pack retention, it is recommended that perforated metal, a little more than 20 per cent open with rather small holes be used. The holes themselves act as resonators at frequencies relative to their size and they provide a few decibels more attenuation, supplementing the acoustic absorptive effect of the pack material. Velocity of the gas across acoustic surfaces is another controlling factor. As the speeds of the gas increases attenuation is reduced. Velocities above 60m/sec are questionable and velocities of 20m/sec ideal. High velocities of themselves will generate noise in downstream piping (17).

Vibration causing noise as previously mentioned can also cause considerable mechanical damage (14). Damage to pressure gauges, valve or pipe-mounted instruments and flange-bolts are some of the many detrimental effects. (See fig.6)

NITROGEN OXIDES EMISSIONS

Oxides of nitrogen are produced in all fossil fuel combustion processes using air as the oxidant.

The major factors known to influence the NO_x emissions include the amount of excess air used for combustion, the heat release and removal rates which define the temperature - time history of the combustion gases, transport effects, and fuel type and composition.

The directional effects of changes in these factors are summarised in Table 5.

TABLE 5 - Major Factors affecting NO_x Emissions (Bartok et al (18)).

Factor	Change in Factor	Effect on NO_x Emissions
Excess Air	Decrease	Decrease
Preheat Temperature	"	"
Heat Release Rate	"	"
Heat Removal Rate	"	Increase
Back mixing	Increase	Decrease
Fuel Type	Coal → Oil → Gas	Coal > Oil > Gas
Fuel Nitrogen Content	Decrease	Decrease
(Method of Firing)	Cyclone → Opposed → Front Wall → Tangential	Cyclone > Opposed > Front Wall > Tangential

Under fuel type above, it will be noted that gaseous fuels have a potential for lowest emission levels.

This can further be explained by the difference in maximum flame temperatures achievable. Theoretically, without dissociation and with stoichiometric combustion, these are 2180°C for coal, 2050°C for oil and 2000°C for natural gas.

Certain further increases in NO_x levels can be ascribed to increases in the concentration of organically bound nitrogen in the fuel. In the case of natural gas this is practically zero while with coal and oil it can be in the range 1.0 to 1.5 per cent and 0.2 to 0.5 per cent respectively.

The following figures have been reported by Elshout and Duuren (19) as characteristic under normal boiler operating conditions.

TABLE 6 - Characteristic NO_x concentration values derived from frequency diagrams of measured values.

Boiler Fired By	Mean Concentration		Concentration Value exceeded in 5% of tests.
	mg NO_2/m^3 normal	kg NO_2/GJ	
Coal	1090	0.41	2000
Oil	510	0.14	970
Natural Gas	290	0.07	460

While the figures for natural gas are lowest in Table 6 it must be noted that uniform emission standards are not set for the different fuels. The U.S. Federal Standards for new plant are - (a) Coal Firing: 0.30kg (as NO_2) per GJ; (b) Oil Firing: 0.13kg (as NO_2) per GJ; (c) Gas Firing: 0.08kg (as NO_2) per GJ.

Potential combustion control techniques for reducing NO_x emissions consist of modifying those equipment operating and design features which affect the high temperature, time duration and presence of excess oxygen during the primary combustion of natural gas. The more important operating modifications have been found to be low excess air firing, two stage combustion, flue gas recirculations and combinations of these techniques. The important design features are burner configuration, location and spacing e.g. with tangential firing, where the furnace itself is used as a burner, as much as 60% reduction in NO_x level has been reported (18). Figures 7 and 8 indicate how reductions can be made in commissioned gas plant if off-stoichiometric firing is employed (Grant (20)). It will be noted that the registers on burners that are out of service and either above or adjacent to "in service" burners are open. Combustion air is reduced on the "in service" burners to an amount less than that theoretically required to provide complete combustion in the primary combustion zone. The idle burner registers provide the remainder of the air and combustion is thus completed at a lower temperature higher up in the furnace.

Experience has shown that when the primary air ratio is approximately 75% of stoichiometric air, low NO_x generation is obtained. As less burners are now employed higher supply gas pressures are necessary and where this has not been possible the burners have been modified to keep the gas pressure within acceptable limits. The burner pattern is largely determined by trial and error and the factors which determine its selection include: NO_x reduction, flame pattern and flame impingement, sensitivity of flame sensing gear, carbon monoxide generation, final live steam and reheat temperature control and the operations involved in load changes.

In the case of gas turbines using either oil or gas, NO_x emission can be reduced substantially where necessary by relatively simple modifications to the combustor as follows:-

(a) Lowering the flame temperature by primary zone leaning.
(b) Reducing the flame residence time by moving secondary diluent holes upstream.
(c) Recirculating a portion of the cooled exhaust products.
It is also possible to reduce NO_x levels by up to 85% by either:-
(d) Direct water injection in the combustor primary zone.
(e) Adding steam to the combustion air.

Using (d) also tends to inhibit smoke production and gives a power increase while (e) does not affect smoke levels but increases the level of CO and hydrocarbons in exhaust gases (Singh et al (21)).

METERING

There are three main options in selecting an orifice metering system for natural gas flows:-

(a) Install an orifice meter in a constant pressure section between two reducing valves permitting the use of a constant factor for supercompressibility in the orifice meter equation.

(b) Install an orifice meter in the main supply line with pressure, temperature and differential pressure measurements linked to a mini-computer containing a correlation for the compressibility factor (e.g. the Standing and Katz correlation (Dranchuk et al (22)).

(c) Install an orifice meter in the main supply line with an accompanying densiometer, thus eliminating the need to calculate the supercompressibility factor.

For case (a) above there is always the possibility of a drift in the pressure and temperature from the set point giving inaccurate readings whereas method (b) only guarantees accuracies of less than 0.5% in the calculation of the supercompressibility of the gas for the range of gas pressures and temperatures expected within a power station confines. With the fast response densiometers available on the market today, it would seem that method (c) leaves the least room for error particularly if two suitable densiometers are used with a reading comparator giving an alarm for differences above a specified figure.

Where the same orifice/s are shared between the supplier and consumer, a "dispute situation" (a difference in flows as measured by each party) will be largely determined by the accuracy of the pressure differential and gas density instrumentation plus an allowance for computational errors. Typical standard deviations for volume flow and mass flow differences could be:-

σ Volume = 0.0615 per cent and Tolerance (Volume) = 0.172 per cent
σ Mass = 0.0580 per cent and Tolerance (Mass) = 0.162 per cent } Shared Orifice

Ideally "Dispute Situations" should only arise for differences in flow greater than an agreed limit around the 0.2 per cent level.

BOILER EFFICIENCIES : N.C.V. VERSUS G.C.V.

Table 7 indicates boiler performance figures for solid, liquid and gaseous fuels using as a basis both the nett and the gross calorific values.

TABLE 7 - Typical Boiler Efficiency Figures.

Fuel Type	Typical Efficiency		Stack Conditions	
	N.C.V. (based)	G.C.V. (based)	Excess Air (%)	Temperature (°C)
Coal	89.69	84.54	48.94	163
Oil	93.42	88.05	15.64	135
Natural Gas	93.86	84.35	14.31	120

It will be noted that on a G.C.V. basis boiler efficiency with natural gas is lowest while on an N.C.V. basis, the efficiency with natural gas is highest. This result stems from the fact that each fuel has a different hydrogen to carbon ratio (natural gas gaving the highest) and it highlights the importance of uniformity in test code calculation methods. It is suggested that the N.C.V. basis be adopted. Recovery of flue gas latent heat tests have in the past been carried out at the Tavazzano Power Station in Italy. However. for this to prove advantageous, it must be assumed that the boiler burns only natural gas. If mixed firing is envisaged, the advantage is not so great and it is for this reason that latent heat recovery has not yet been availed of on an industrial scale.

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SYMBOLS

adb = sound intensity (decibels);
db = sound intensity (decibels);
g = gravitational acceleration (m/s^2);
G.C.V. = gross calorific value (MJ/M^3);
I.D. = induced draught;
MMcf/d = million cubic feet of gas per day;
N.C.V. = nett calorific value (MJ/M^3);
NO_x = nitrogen oxides;
P.P.M. = parts per million by volume;
δ = gas coefficient (s/cm);
λ = wavelength (m μ);
σ = standard deviation;
τ = time constant (S);

CONVERSION FACTORS

1 kp = 9.81 newtons;
1MMcf/d= 0.3277 m^3/s;

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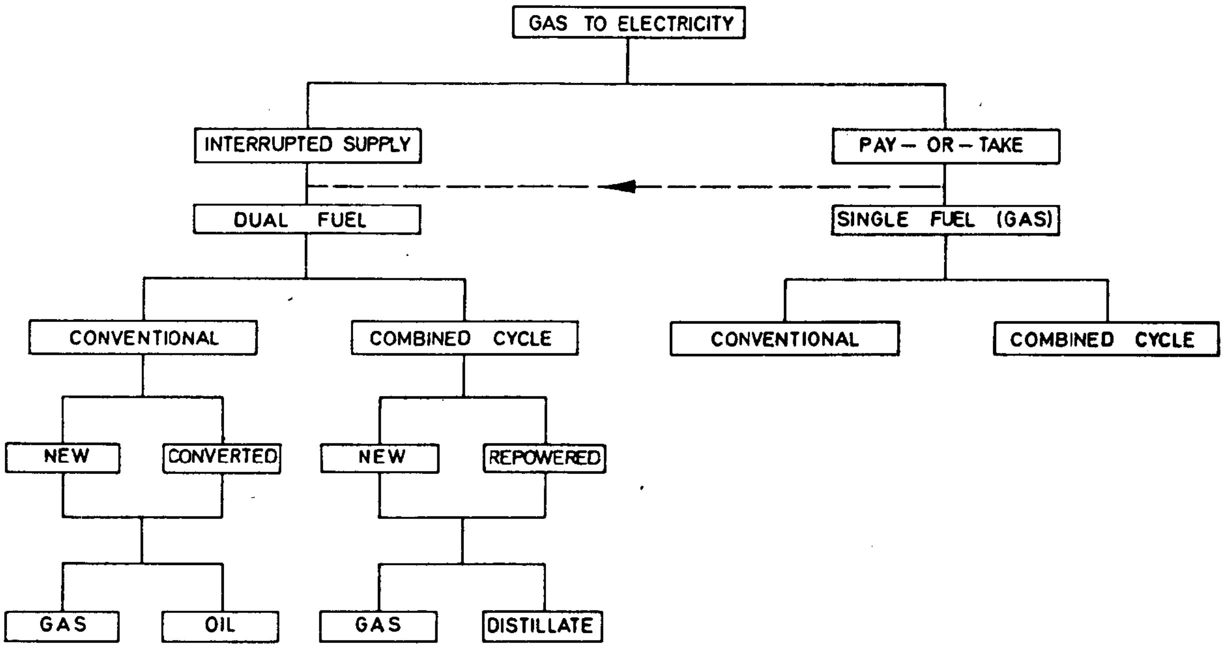
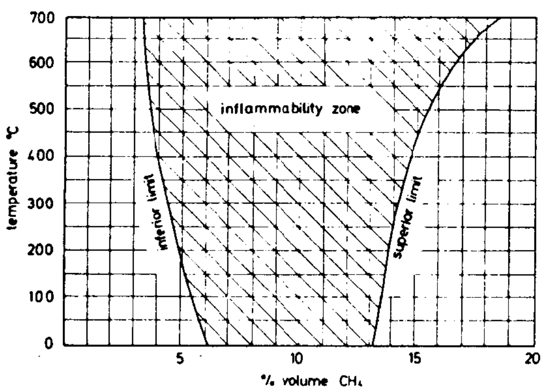


Figure 1 Alternative Gas-Fired Plant.



Type of fire	Dry chemical flow rate lb./sec.	Dry chemical quantity* lb.	Natural gas fire size ft.³/sec.	
			Sod. bicarb	Pot. bicarb
Vertical jet	5	150	5	180
	10	300	20	360
	20	600	79	720
	40	1,200	320	1,400
Horizontal impingement, short preburn	5	150	22	170
	10	300	44	260
	20	600	88	420
	40	1,200	180	670
Horizontal impingement, long preburn	5	150	7	79
	10	300	14	120
	20	600	28	200
	40	1,200	57	310
Downward impingement, short preburn	5	150	22	44***
	10	300	44	88***
	20	600	88	176***
	40	1,200	176	350***
Downward impingement, long preburn**	5	150	7	14***
	10	300	14	28***
	20	600	28	56***
	40	1,200	56	110***
Slit pipe, short preburn	5	150	3	12***
	10	300	12	49***
	20	600	49	121***
	40	1,200	121	166***
Slit pipe, long preburn**	5	150	1	4***
	10	300	4	16***
	20	600	16	40***
	40	1,200	40	54***

* Quantity of dry chemical based on 30-second effective discharge time.
** All data estimated from results with sodium bicarbonate-base dry chemical on long preburn horizontal impingement fires.
*** Estimated on basis of potassium bicarbonate-base being twice as effective as sodium bicarbonate-base.

Figure 2 Ignition Limits for Air-Methane Mixtures.

Figure 3 Recommended Minimum Flow Rates and quantities of dry chemicals to extinguish natural gas fires.

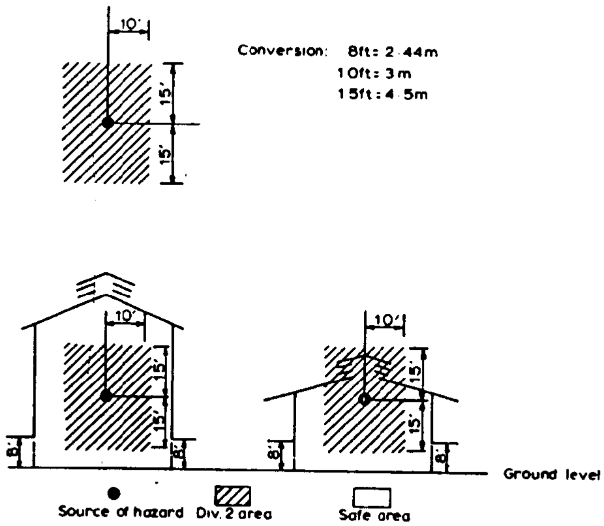
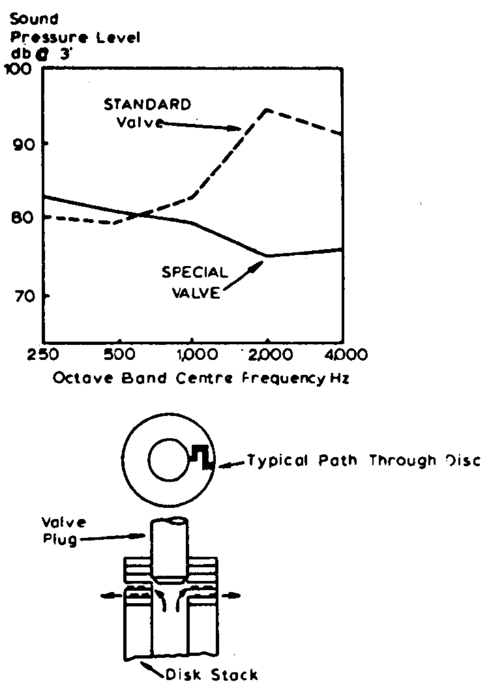


Figure 4 Top: Open air situation. Bottom: Open building situation.



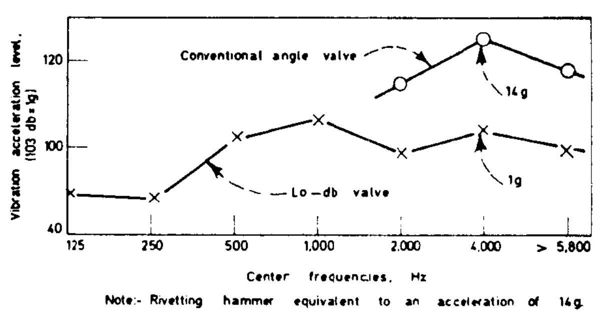


Figure 5 Control Valves: Effectiveness of special designs.

Figure 6 Vibration Acceleration levels when reducing 0.11×10^6 m^3/hr gas from 27500 kN/m^2 to 15850 kN/m^2.

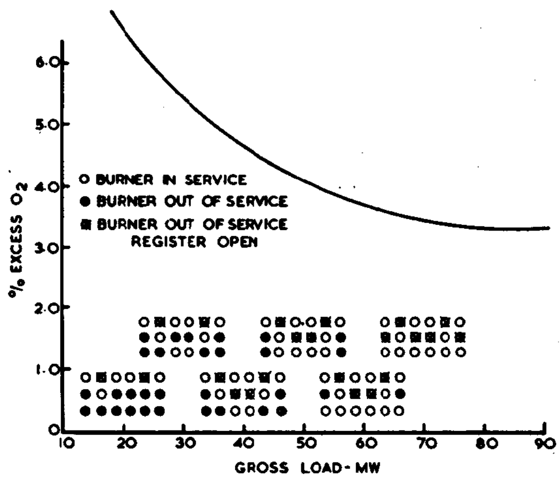


Figure 7 Operating Procedure.

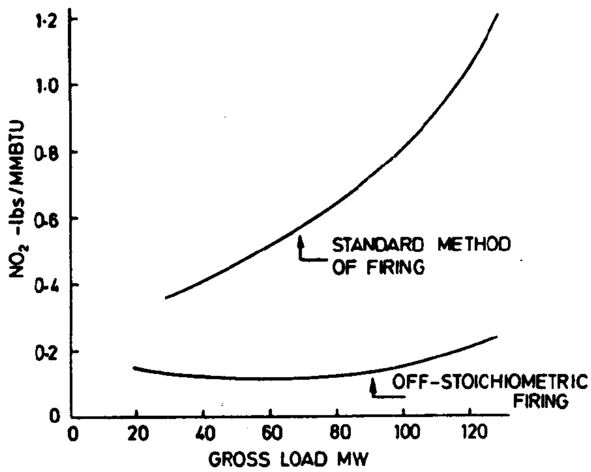


Figure 8 NO_2 Reduction.

ECONOMIC EVALUATION OF LNG & METHYL FUEL

R. J. Deam and J. Leather*

The conventional comparisons between LNG and Methyl Fuel suffer from one or more of the following defects. (1) It is assumed that the price of gas is a necessary input to the calculations, and since price can only be surmised, the comparison is necessarily imprecise. (2) The possibility is ignored that the optimal supply routes for LNG and Methyl Fuel can be quite different. (3) The comparisons are carried out on a calorific basis. Through the use of a world petroleum natural gas model it will be shown how these defects are corrected, and how the optimum mix and location of LNG and Methyl Fuel production as well as end use are determined.

INTRODUCTION

Because of the quality of transportation advantages, or because of political or physical constraints on the rate of production, it may be assumed that most of the world's sources of crude oil will be used to the limit. Fluctuations in demand consequently fall on a few, and at equilibrium on one, crude source. We call this source the marginal supply. Its identity changes over time; during the fifties it was Iranian, in the sixties Kuwait and at present it is light Arabian crude.

Previous papers (1), (2) showed that, given the price of the marginal crude source, the price of all oil products in the international trade in each consuming area can be determined from technological factors and engineering cost data. In illustration O'Carroll has shown (3) that average quarterly wholesale product prices at Rotterdam over the period 1967 to 1971 calculated from the World Energy Model agree well with actual prices (see Fig.1). The only oxogenous market price necessary was that of the marginal crude oil, which was at that time, Kuwait.

The solution of the model system describes an equilibrium condition, in which the cost of meeting a stated demand pattern is minimised. In the study of systems at equilibrium, the concept of "degrees of freedom" is often invoked; the number of degrees of freedom is the number of variables which must be specified in order that the state of the system may be completely defined. From our analysis it has been concluded:

(1) The system involved in determining product prices in international trade has one degree of freedom. Given the identity and the price of the marginal supply of energy, and the time lags in the system, the prices of all energy products are determined by technology and engineering costs.

(2) The results are compatible with the hypothesis that the oil industry is highly competitive.

(3) The model is a practical representation of the realities of the international trade in oil and gas.

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There is a range within which the price of the marginal crude oil must lie; this range is clearly defined at the lower end but less so at the upper. The lower limit corresponds to the cost of production. Should the price fall below its cost, which has been estimated to be about 10-15 cents bbl, none would be produced. Should the price rise above that of an alternative marginal source (syncrude, tar sands or whatever) then in due course, when sufficient of the alternative is being made, the production of the original marginal source would cease. Thus the feasible long-term price of light Arabian crude lies between two wide limits; the energy problem is really to decide what will be the next marginal energy source.

<u>The relationship between the price of crude and of natural gas.</u>

The relationship between the price of crude oil and natural gas is a complex one. Here we illustrate one possible relationship in the international market through the methyl fuel route.

Natural gas converted to "methyl fuel" can substitute for # 2 furnace fuel oil as a burning fuel, provided they are at the same BTU equivalent price.

Whilst it is not possible to determine the equilibrium situation without solution of the World Energy Model it is shown here that a possible approximate equilibrium relationship can be obtained quite simply. The relationship is shown in the following Table.

Let P_C be the price fob in $/bbl of the marginal crude.

	$/bbl	$/ton	¢/Therm
Crude (fob Persian Gulf) per unit of furnace FO	$1.2P_C$	$8.8P_C$	
Freight to USEC per unit of furnace FO	1.62	12.00	
Built up cost of cracking per unit of furnace FO	2.03	15.00	
Value of furnace fuel oil	$1.2P_C+3.65$	$8.88P_C+27.00$	$2.07P_C+6.28$
Hence value of methyl fuel at USEC		$5.28P_C+16.1$	$2.07P_C+6.28$
(less) Freight per unit of Methyl fuel		(3.33)	
(less) Manufacturing cost of Methyl fuel		(18.84)	
Netback manufacturing cost of Methyl fuel		$5.28P_C-6.16$	$2.07P_C-2.42$
(less) fuel and loss			$0.89P_C-1.04$
Well-head value of gas			$1.18P_C-1.38$

Notes: the following assumptions are made.

(1) 1 ton of furnace fuel oil made by cracking requires 1.2 tons crude.

(2) Cost of cracking of $15.00 per ton is a historical European average for 1967-71. The actual figure would depend on the severity required (illustrating the need for a world model).

(3) "Methyl fuel" (consisting of $\frac{2}{3}$ methanol, $\frac{1}{3}$ higher alcohols among which isobutanol is predominant*) has 60% of the calorific value of furnace fuel.

(4) Natural gas is in general closer to the market than crude say $\frac{1}{3}$ the distance.

(5) Capital cost of methyl fuel plant depends on location. The figure obtained privately from several contractors of $\$67$ per ton per annum leads to a manufacturing cost made up as follows:

		$\$$/ton product
Capital charges (15% over life)	18%	12.06
Maintenance	4%	2.68
Operating costs		4.10
		18.84

(6) 1 therm of methyl fuel requires 1.75 therms natural gas.

(7) Calorific value of furnace fuel 430 therms/tonne, methyl fuel 255 therms/tonne.

This rough calculation demonstrates the way in which the prices of oil are necessarily connected. If Persian Gulf crude is marginal, its price will determine that of gas. According to the calculation above, if $P_C = 10\$/\text{bbl}$, then the price of gas is about 10 cents per therm. If some other processes (e.g. LNG, Fischer Tropsch) were cheaper than methyl fuel manufacture, gas would have a higher value.

<u>Methyl fuel vs.LNG</u>.

The literature abounds with calculations of the relative merits of LNG and methyl fuel as means of transporting large volumes of natural gas over large distances. It is our submission that these calculations suffer from one or more of the following defects:

(a) It is assumed that the price of gas is a necessary input to the calculation, and since this price can only be surmised, the comparison is necessarily imprecise.

(b) The possibility is ignored that the optimal supply routes for LNG and methyl fuel can be quite different.

(c) The comparisons are carried out on a calorific value basis.

In the last section it was shown that at equilibrium the price of natural gas is linked to that of crude oil, and that while crude oil is the marginal source of energy, its price will determine that of gas through whatever technological mechanisms are in operation at any given time. The price of LNG or methyl fuel is fixed by that of the oil products for which they are substituting; the price of gas is that price less the prices charged for conversion and transport. In other words it should be assumed that at equilibrium the gas producer will collect the rent and the operator can expect only "normal" profit levels.

As to the supply patterns, it should be considered whether, in transporting energy from Algeria to the USA for example, methyl fuel manufactured in Algeria might be absorbed in Europe, and the oil products which it displaces exported to the USA, thus saving on shipping costs per therm. Such a route might not be available for LNG in view of the indigenous gas production in Europe and the possibilities of importing pipeline gas from Russia. This is a type of problem which can only be tackled with a World Energy Model representing the alternative supply possibilities and the local demand patterns.

* Latest information suggests $\frac{3}{4}:\frac{1}{4}$ higher alcohols can be made in practice.