A PROPOSED SYSTEM FOR CAPTURING ENERGY FROM VENTILATION AIR METHANE

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ABSTRACT

The greenhouse gas (GHG) radiative forcing factor of methane is often quoted as 23 times as potent as carbon dioxide on a 100-year time horizon; thus, any reduction in atmospheric methane would be globally beneficial. The capture or use of ventilation air methane (VAM) is challenging because it is a high volume low concentration methane source. This results in the routine discharge of methane into the atmosphere.

A review of VAM mitigation technologies is provided and the main disadvantages of the existing technologies are discussed. In the proposed VamTurBurner© system, the heat from the combustion chamber is transferred to the preheating zone either by a heat exchanger or by redirecting the combustion products to mix with the ventilation air stream from a coalmine. Gas turbines (GT) are used to produce electricity with the exhaust gases directed to mix with the incoming ventilation airflow. The turbulence introduced by the GT exhaust assists with mixing of the incoming ventilation airflow and the return flow of combustion products from the combustion chamber. The combustion products are a source of heat, which increases the temperature of the incoming ventilation air to a value high enough for the methane to undergo flameless combustion upon encountering the igniters.

The high temperature combustion products enter a multi-generation system. The multi-generation system is based on mature engineering technology such as heat exchangers and steam turbines. The residual heat provides additional heat based products such as industrial scale drying, chilling by an absorption chiller or simply hot water.

The VamTurBurner© uses the energy from the GT, igniters and VAM to provide clean efficient energy while mitigating the atmospheric emissions of methane. The opportunity to collect carbon credits may improve the economics. Since the VAM is a free energy source, the output of the system is greater than the purchased energy.

KEYWORDS

Ventilation air methane, VAM, Combustion, Coal mining, Ventilation, Gas turbine, Greenhouse gas, GHG, Methane mitigation, Carbon credits, Energy capture, Coalmine methane, CMM, cogeneration, multigeneration.

1. INTRODUCTION

Methane is a greenhouse gas (GHG), with a global warming potential of 56, 21, and 6.5 over 20, 100, and 500 years, respectively, where the reference of unity is used for carbon dioxide (1). Methane has a high radiative forcing factor second only to that of carbon dioxide (2). These two attributes exacerbate the impact of methane emissions on the near term global temperature. According to the long-term modeling of global temperature rise due to carbon dioxide forcing, the temperature increases are not globally uniform. Northern regions are more inclined to experience higher marginal increases in temperature than the equatorial regions or the Southern hemisphere, due to the global redistribution of heat from the equator to the poles and the moderating influence of the oceans in the south. This expected increase of temperature in the northern region has the potential to create a strong methane feedback effect if the methane contained in the permafrost is released into the atmosphere as the permafrost melts (3).

1.1. A RADIATIVE FORCING FEEDBACK LOOP IN THE ARCTIC

Since the dawn of the industrial age, carbon dioxide and methane have increased by 31% and 149%, respectively. Human activity accounts for more than two-thirds of the increase in methane (4). The present atmospheric concentration of methane is an average of about 1800 ppb, which is quite abundant in the atmosphere compared to the values a few centuries ago (5). An escalation of methane in the atmosphere confirmed an increase of 12.5% over the last 33 years (6). Arctic methane levels during August ranged from 1840 ppb to 1860 ppb in 2012 compared to 1830 ppb to 1850 ppb in 2011 and 1820 ppb to 1840 ppb in 2003 (7, 8). In the year from August 2011 to August 2012, the average Arctic methane levels increased by about 10 ppb (7, 8) compared to an increase of 10 ppb over the previous 8 years since 2003, see Figure 1. The effect of the rate of methane increase in the Arctic for 2011 to 2012 is equivalent to the radiative forcing that an increase in carbon dioxide of about 250 ppb to1,000 ppb, or 12% to 50%, would have for that single year (7). This recent and rapid increase in Arctic methane concentration may be an early indicator of an Arctic methane radiative forcing feedback loop. The result of such a feedback loop leads to accelerated permafrost melting, an increase of the Arctic ice-melting rate and both effects influence the global temperature upward (9).

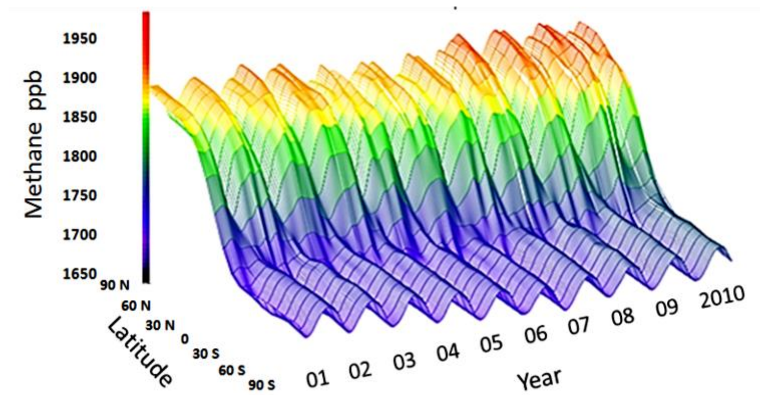


Figure 1 – Three dimensional plot of the Global Distribution of Atmospheric Methane NOAA ESPL Carbon Cycle over the last decade from the equator to the North Pole (10)

Other effects such as the increase in exposed land or decrease in the albedo due to a loss of ice cover compounds the problem adding to the potential for warmer temperatures. This could result in greatly increased Arctic heating along with more extreme weather events and glacial melting effects far exceeding the impacts we see today.

"Scientific climate projections do not currently account for carbon emissions from permafrost, but the study concludes that the effect is "strong enough to warrant inclusion in all projections of future climate."(11).

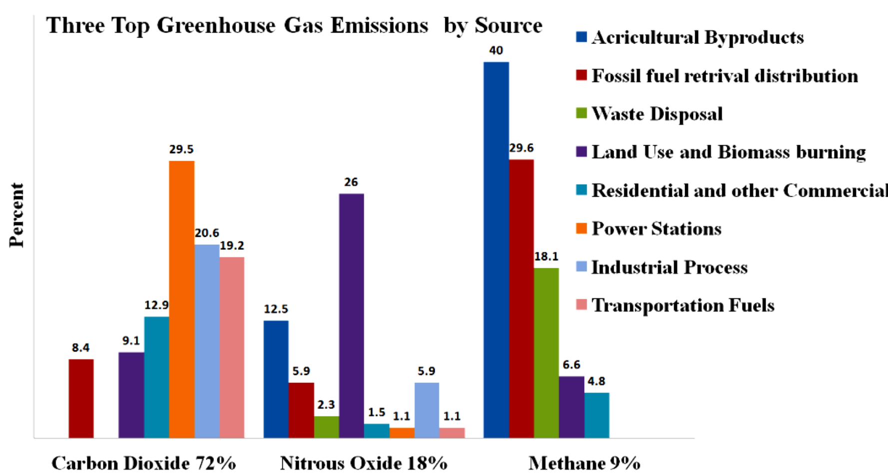


Figure 2 –Annual greenhouse gas emissions by sector (12)

Figure 2 shows the distribution of the three top GHG's by their sector source carbon dioxide, methane, and nitrous oxide. The GHG effect of methane, which accounts for 9% of the total GHG emissions, is not discussed as frequently as carbon dioxide. Methane is a higher radiative forcer over a shorter term; thus, a small amount of methane has a large effect on the global thermal horizon over a shorter period. Upon consideration of the effect of methane releases in the Arctic, the urgency of methane mitigation programs becomes self-evident.

2. ATMOSPHERIC METHANE EMISSIONS FROM COAL MINES

Table 1 – Global anthropogenic methane by sector from three sources.

Agency/	IEA CCC	M2M	US EPA
Source	2005 (%)	2006 (%)	2006 (%)
Natural Gas	15	16	17
Coal	8	8	6
Oil	1	1	1
Solid Waste	13	14	12
Waste Water	10	11	9
Fuel	1	1	1
Biofuel	4	4	
Other Agriculture			7
Biomass	5		3
Fermentation	28	29	30
Manure	4	4	4
Rice	11	12	10

The atmospheric concentration of methane, associated with coal mining, see Table 1, is estimated to be about 8% of the total anthropogenic methane produced (4). The largest fraction of atmospheric methane from coal mining activities is due to VAM release. Methods to mitigate VAM are desirable from a global climate perspective and could be economical if the generated heat is captured. Since methane is a GHG targeted for mitigation, VAM from coal mining operations or abandoned mines is an obvious candidate.

A typical gassy coalmine has five sources of methane (13):

1. Degasification or drainage systems at underground coalmines.
2. Ventilation air containing dilute methane concentrations or VAM.
3. Nonoperational mines from vent holes or through fissures.
4. Open pits directly exposed to the atmosphere.
5. Post-mining operations where the coal emits methane during storage or transportation.

VAM stands out as the intractable methane resource to exploit because of the low methane concentration and high volumetric flow, while the other methane sources are typically higher concentrations at lower flow rates. The US data presented in Table 2 are representative of the typical emissions of global mines. The VAM emissions from US coalmine ventilation systems are from 61% to 70% of the total coalmine related methane emissions (14, 15).

Typical methane percentages in the ventilation air are in the neighborhood of 0.2% to 1% v/v, but vary in concentration as the atmospheric pressure changes, the underground operations change, the mining proceeds deeper or in the event of seismic activity. The concentration of methane in ventilation air is kept low, mainly for safety reasons (16). The flow rates needed to keep the methane from a coalmine at low concentrations in ventilation air can typically be 100 m^3/s, but can reach as high as 300 m^3/s. The comparison of anthropogenic methane sources in Table 1 shows that coal mining is responsible for about 8% of all emissions, which are broken into the various mining activities in Table 2. From the values in Tables 1 and 2, VAM accounts for about 5% of the total anthropogenic methane.

It is clear from the calculations presented in Table 3, that the economic benefit of converting the fugitive methane emissions could provide a significant enhancement to any engineering project undertaken to mitigate the VAM. Essentially the VAM is a free energy source and according to the current climate models, mitigating a GHG with a carbon dioxide equivalence of 21 would be beneficial.

Table 2 – USA Methane emissions by coal mining activity source (U.S. Emissions Inventory)

	Average 1990–2009		2010	
Mining activity	bcf	%	bcf	%
Post mining	19	10.06	18.87	9.86
Surface mines	31.9	16.90	32.64	17.06
Abandoned mines	13.6	7.20	12.32	6.44
Drained gas			9.49	4.96
Degasification vented from UG	9.4	4.98		
VAM	114.9	60.86	118	61.68
Total bcf	188.8		191.32	

Table 3 – Power available and carbon dioxide equivalents for mitigation of various typical methane concentrations in typical ventilation flows of a coal mine

Ventilation flow rate (m^3/s)	Methane concentration (%)	Methane mass flow kg/s	Methane tons/yr	Conversion to carbon dioxide tons/yr	21 times equivalent carbon dioxide tons/yr	Power (MW)
50	0.2	0.068	2144	5897	39136	3.77
150	0.5	0.51	16083	44289	293521	28.30
300	1.0	2.04	64333	176917	1174085	113.22

All projections suggest a continued increase in global energy demand and unless some major change, such as the implementation of a carbon tax, coal is expected to play a major role in the future energy supply of China, India, and the US. Regardless of whether technologies evolve to provide a cleaner coal burning plant, it is inevitable that more coal will have to be mined. China currently produces 71% of its energy from coal (17). The US, China, India, Australia, and Indonesia account for more than 75% of global coal production.

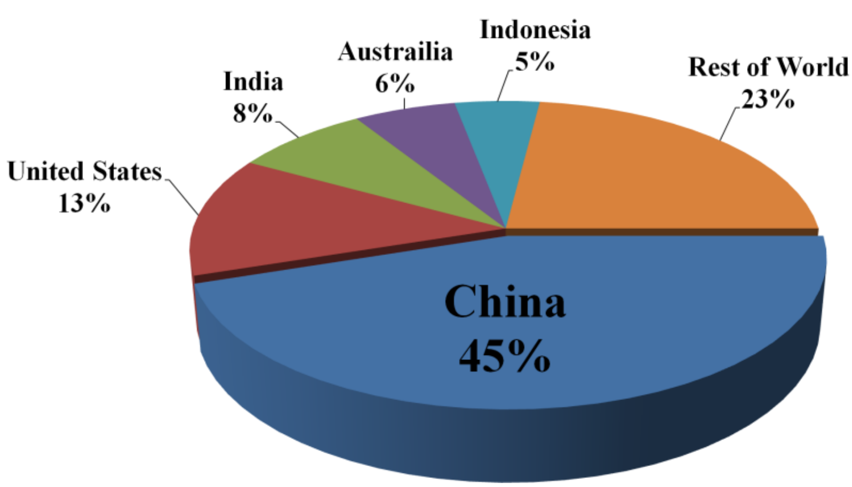


Figure 3 - Percent distribution of coal production for the top 5 producers and the rest of the world (18)

The estimated quantities of VAM emissions, see Figure 4, associated with these production quantities suggest the world market for VAM destruction technologies has a potential value of several billion dollars (19). Over the last decade, China and Indonesia have nearly doubled their production and although the US has reduced coal production somewhat, India has recently started to grow at a more rapid pace, which carries the expectation that their coal use will also increase. The VAM has clearly been increasing in the countries where the coal production has increased.

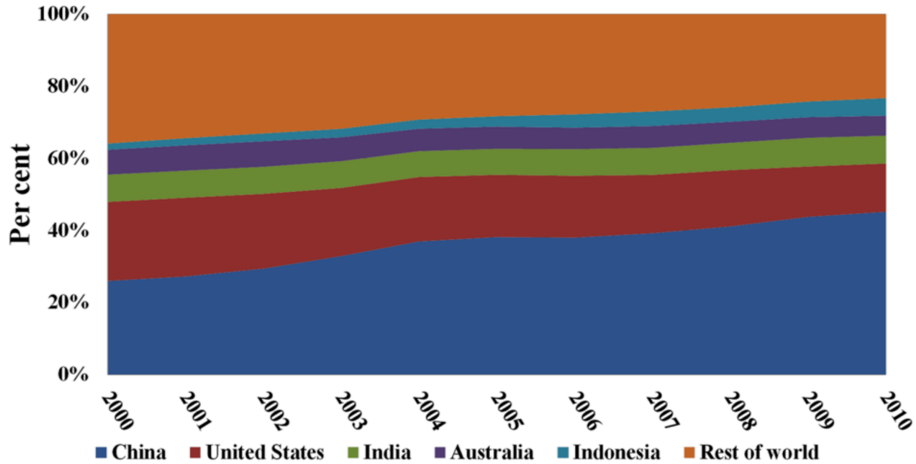


Figure 4 – Percent distribution of VAM emissions for the top five producers and the rest of the world (17).

3. A REVIEW OF VAM MITIGATION TECHNOLOGIES

A number of technologies have been developed to mitigate VAM, but there are essentially two basic methods. VAM is a primary fuel when used in Thermal Flow Reverse Reactors (TFRR), Catalytic Flow Reverse Reactors (CFRR), lean burn GT's, recuperative GT and Regenerative Thermal Oxidation (RTO) (20, 21, 22). When the VAM replaces air in a combustion process, such as a GT, an internal combustion engine, in rotary kilns and a coal fired power station, it is a secondary fuel residing in the intake air. Higher concentration sources of methane, such as drained sources or Coal Mine Methane (CMM), can be flared, mixed with the VAM to boost the calorific value of the VAM when it is used as a secondary fuel or sold to market.

The Commonwealth Scientific and Industrial Research Organization (CSIRO) built a 1.2 MW rotary kiln system, where waste coal and VAM are burned in a rotating kiln to generate electricity by using an externally fired steam turbine system (23). The VAMCAT™ is a lean burn catalytic gas turbine custom-built for VAM that operates on 0.8% methane using an innovative catalytic combustion gas turbine system to oxidize methane while generating electricity (24). A 25kW$_e$ power generation demonstration operated at an underground coalmine of the Huainan Coal Mining Group, China during November 2011.

The VOCSIDIZER© was first established as a viable option to mitigate VAM in 1994 at the Thoresby Mine in Nottinghamshire, UK (25). The result of that demonstration proved the capability of the VOCSIDIZER© to maintain an oxidation reaction at the low and varying concentrations of methane found in a typical coalmine ventilation system.

The results from the Thoresby Mine lead to scaled-up testing performed in 2001-2002 at the Appin Colliery in New South Wales, which included an internal heat exchanger to capture the heat of combustion. The project operated over a one-year trial period; a robust demonstration of the technology (26). This project confirmed that a TFRR with a heat exchanger could provide energy for an assortment of potential applications such as hot water for the company or the community, hot air for space heating, industrial drying, cooling using low grade heat with an absorption chiller or electricity generation. Consequently, MEGTEC and BHP Billiton installed a large-scale electrical power generation project at the West Cliff Colliery in New South Wales (27).

The West Cliff VAM Project or WestVAMP was the world's first commercial-scale VAM project, which began operation in Windsor Mine in April 2007. WestVAMP oxidizes 70 m^3/s of 0.9% methane. The concentration is maintained at a constant flow rate by mixing drainage gas with the ventilation exhaust airflow. The 6 MW$_e$

generated is used by the West Cliff colliery. The heat collected from the VOCSIDIZER© units is used to provide superheated steam to conventional steam turbines producing electrical power (28).

Apart from the UK and Australian projects, MEGTEC has also demonstrated their VOCSIDIZER© technology in the US at the CONSOL Energy Windsor Coal Mine, a closed mine in West Liberty, West Virginia (26). The project operated for 20 months to demonstrate the reliability of VAM conversion, using drained methane from the closed workings, simulated at a 0.6% concentration and a 14 m^3/s flow rate. The project determined the available energy that can be extracted from the system.

The Zheng Zhou Coal Mining Group in China operates a system, based on the MEGTEC VOCSIDIZER©, that they use for VAM abatement and energy recovery to produce hot water for local use. The system was commissioned in October 2008. It has an 18 m^3/s system capacity while operating on a nominal VAM concentration of 0.3% to 0.7%. The VOCSIDIZER© was the first VAM mitigation project to be officially approved by the UNFCCC for allocation of Kyoto related Carbon Credits (29). The system requires a minimum of about 0.2% VAM to maintain the oxidation reaction.

Diesel engines are routinely used to provide electricity to mines in remote locations, which can be used to reduce the VAM emissions provided the installation be designed to avoid costs associated with transportation of the VAM (30). The 54 internal combustion engines that are powering the electricity generation project at the Appin Colliery in New South Wales are comprised of 1 MW units. The VAM and CMM driven internal combustion engines can produce up to 55.6 MW_e for the mine (27). Forty more units at the Tower location provide a combined output of 97 MW_e from 94 Caterpillar 3516LE generators. In this case, VAM is a supplemental fuel thatcontributes a portion of the fuel input through the normal air intake to the IC engines. All of the drained gas from the mine is used, accounting for 4% to 10% of the required engine fuel, but only about 20% of the VAM emissions are mitigated.

A pilot-scale study, performed at the Vales Point Power Station (31), determined the feasibility of using a ventilation air stream containing VAM as a portion of the air supply required for combustion; however, the coalmine and power station are conveniently proximal. A full-scale demonstration, with the support of an Australian federal government program in 2003, directed a VAM flow rate of about 220 m^3/s to the intake of the power station. Total air consumption for the two 660 MW pulverized coal fired boilers at the power station is approximately 1200 m^3/s. Using ventilation air as part of the air supply needed for combustion in large boilers requires that the power plant and the mine be located within reasonable proximity to limit transportation issues. These possibilities are limited, while the more flexible internal combustion or diesel engines are routinely installed at remote locations.

A demonstration project undertaken in 2004 at the Appin Colliery mine employed a 2.5 MW Solar Centaur 3000R GT modified to use an airflow containing about 1.6% methane (16). The trials were suspended when the contamination of the mine air had an adverse effect on the operation and stability of the gas turbine, which caused the combustor heat exchange tubing to over-heat and fail.

The FlexEnergy Micro turbine was adapted, with a catalytic combustor, to operate on a wide range of fuels including VAM. The FlexEnergy unit can achieve full power with fuel as low as 1.5% methane. The compressor and combustor are contained within a compact turbine module and the hot compressed gases are allowed to expand in the turbine to power the generator (32). A FlexEnergy turbine was installed at the DCOR oilfield near Santa Barbara, California to consume oilfield gas at concentrations ranging from 1.5–4.2% and another consumes coal process waste gas at the Western Research Institute in Laramie, Wyoming.

Fluidized beds operate on the terminal velocity principle, such that the upward flow suspends solid particles in the flow. The resultant turbulent mixing of gas and solids provides a bubbling action, which affords for a high chemical reaction rate and heat transfer. The technology is still a proposed concept, with no development to date (32).

Catalytic monolith reactor technology comprises a honeycomb shaped monolithic reactor. By virtue of the geometry, exceptional flow profiles at a low pressure drop due to low resistance and high mechanical strength are realized. Monoliths consist of a structure of parallel channels with walls coated by a porous support containing catalytically active particles. The methane in the flow is oxidized as it comes in contact with the catalyst on the substrate of the monolith.

Sindicatum acquired the global rights except for Japan until 2019 to use the "CH4MIN" catalytic oxidation technology that has been developed by the Centre for Mineral and Energy Technology (CANMET), a Canadian government energy research organization that is part of Natural Resources Canada. Sindicatum performed full-scale testing of this technology during 2008 and 2009 at a location in the US to facilitate the design of a commercial regenerative catalytic oxidizer the first one of which will be installed at Duerping coalmine, Shanxi Province, China.

3.1. DRAWBACKS OF THE CURRENT TECHNOLOGY

The current systems capable of VAM mitigation, while using the VAM as a primary fuel, such as the TFRR and CFRR, generally do not use all the VAM to produce an energy product because some of the energy is required to sustain the oxidation reaction. The plots shown in Figure 5 are representative of the operation of a generic TFRR or CFRR in heat recovery mode. The amount of reaction sustaining methane required is 0.12% for the TFRR and 0.45% for the CFRR and at lower VAM concentrations additional fuel or electrical heat supplementation is required (34). The cutoff of 1.3% represents the methane concentration at which heat would have to be discarded due to the high temperatures that would damage the reactors. Since some of the energy is consumed to sustain the heat of the reaction not all of the heat is available for recovery for example, for a VAM concentration of 0.7 the TFRR can recover 75% of the energy while the CFRR recovery is only 34%. These systems introduce a pressure drop, due to the resistance encountered as the ventilation air stream flows through a bed of ceramic beads or gravel (35), which require supplemental fans to overcome (36).

The projects using VAM as a secondary fuel, such as the Appin Colliery (27) and as a supplement to air supply for combustion such as the Vales Point Power Station (31) are successful projects. One drawback is that the amount of VAM used as a secondary fuel depends on the normal air-intake flow rate of the combustion system, therefore, the number of generator units needed to accommodate the ventilation air in place of normal airflow is prohibitively large. A second drawback is the need for consistent fuel concentrations and supplementation of the fuel to a minimum concentration for proper operation of the engines. For example, the VAMCAT, a 30 kW_e microturbine, has an airflow of about 0.08 m^3/s (34) so a typical 100 m^3/s ventilation airflow would require 1200 VAMCAT units. In the case of the Appin Colliery electrical generation project, 54 internal combustion engines are comprised of VAM/CMM driven internal combustion engines that can produce up to 55.6 MW_e (37) and with 40 more at the Tower location a total 97 MW_e is produced from 94 Caterpillar 3516LE generators. The need for such a large number of units, to make use of the full amount of the VAM available at the mine, may prevent a given project from realizing the full potential of the available VAM. In the case of the power station usage, the drawback is the proximity of the locations, but in the rare instance that a power station is conveniently located close to the mine it is an excellent methane mitigation solution. Improved economics may be realized by the installation of a system capable of converting all of the VAM to a useable energy product. The VamTurBurner©, currently in the early design stages of development, is proposed as an alternative to the existing systems (34).

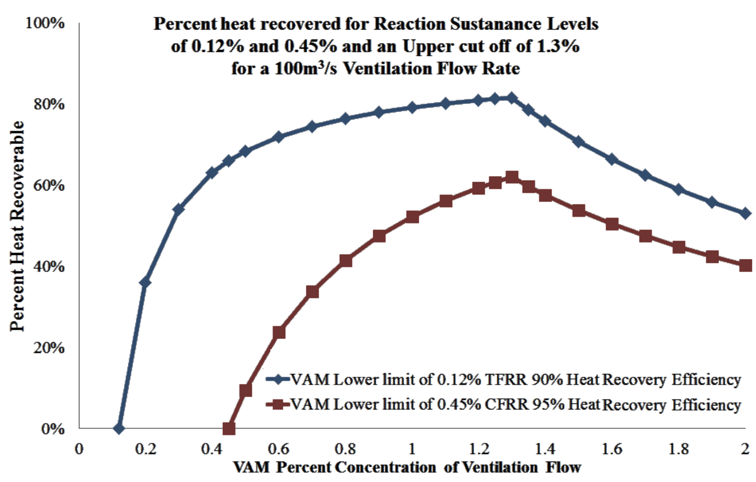


Figure 5 – Recoverable energy available after reaction sustaining fraction is removed.

4. THE VAMTURBURNER©

The VamTurBurner© is a proposed methane mitigation system targeting coalmine ventilation air methane. The concept is based on the principles of flameless combustion for lean premixed fuels. The principle of operation is that given sufficient preheating, a lean fuel air mixture will ignite and undergo flameless combustion in the presence of an ignition source. In the case of VAM, the temperature of the incoming ventilation air is raised to a value that, depending on the concentration of methane, will undergo flameless combustion. The temperature increase of the ventilation airflow is accomplished by recirculating thermal energy from the combustion chamber back to the incoming airflow at the preheating zone. The heat is transferred to the preheating zone via a heat exchanger or by redirecting the combustion products back to the preheating zone to mix with the incoming ventilation air. The turbulence introduced by high velocity exhaust gas exiting a Gas Turbine (GT) promotes mixing of the two air streams. GT's are frequently configured for cogeneration, electrical generation and waste heat utilization, in this application the waste heat contained in the GT exhaust gas is used to increase the temperature of the ventilation air while introducing turbulence to the preheating zone. The preheated ventilation air stream then flows to encounter the igniters, which cause the preheated air fuel mixture to undergo flameless combustion. It is anticipated that the VamTurBurner© VAM mitigation solution will allow for the majority of the energy, except typical losses due to heat transfer to the external environment and conversion efficiencies, to be captured and used to produce electricity or other thermal products. The output of the system, the combustion products, is a high temperature gas. The high temperature gas is used in standard heat exchange systems to produce high quality steam for electricity generation followed by further energy transfer systems used to produce other thermal products such as hot water, chilling or industrial drying as needed. The design of the heat exchangers and steam turbine systems in the final section of the equipment are based on mature technology and standard engineering; thus, are not the subject of this work.

The CFD modeling described herein was undertaken to explore preliminary design concepts for a heat exchanger or direct mixing as a means of providing the preheating. In addition, to confirm that the conceptual design has the capability of sufficiently mixing the combustion products with of the ventilation air stream, such that the temperature distribution at the igniters is as uniform as possible to ensure that the maximum methane combustion is achieved. The typical base case of 100 m^3/s ventilation airflow with VAM concentrations from 0.5% to 1.4% was used to confirm the design concept is useful for the mitigation of ventilation air methane from coalmine sites.

In Figure 6, a conceptual or block diagram of the VamTurBurner© VAM mitigation system is shown. The ventilation air from the upcast ventilation raise of the mine enters the VamTurBurner© system through a coupling to the evasé, not shown on the diagram, and the ventilation stream is directed through ducting to the preheating zone. The mine air may contain hydrogen sulphide, sulphur dioxide and dust (38) that could reduce the GT lifetime, as was experienced during the Solar Centaur 3000R trials. A key feature of the design is a separate air intake system for each of the GT's, the fresh air intake is shown protruding from the system ducting in Figure 6, the fresh air intake prevents mine ventilation air from entering the GT, which ensures the operating conditions expected by the GT are provided. The GT's operate on natural gas or an appropriate fuel as shown on the diagram. These design features promote the smooth operation of the gas turbine due to fresh air intake and properly regulated fuel.

The exhaust gases from a GT are typically in the neighborhood of 500 K to 700 K and exit the GT at a high velocity in the neighborhood of 50 m/s. These values are assumed as generic boundary conditions for modeling the airflow interactions. The high velocity exhaust gas mixes with the incoming ventilation airflow and combustion products in the preheating zone, represented only figuratively by the hot and cold return in Figure 6, see Figure 15 for the CFD modeling of the mixing in the combustion chamber. The interaction between the high velocity GT exhaust, the ventilation air and combustion products provide sufficient turbulence to mix the co-flows satisfactorily, a key design feature required to distribute the heat evenly throughout the volume to allow complete combustion of the methane in the combustion chamber.

The lower the methane concentration, or equivalence ratio, the higher the preheating temperature required for an air methane mixture to undergo oxidation or flameless combustion (33). Therefore, the amount of preheating required is a critical variable that requires feedback to correlate the heat transfer to the preheating zone to the incoming ventilation air methane concentration. The preheated flow proceeds through the ducting where it encounters the igniters that may be fueled by natural gas, supplemented by CMM available at the site or any suitable liquid fuel.

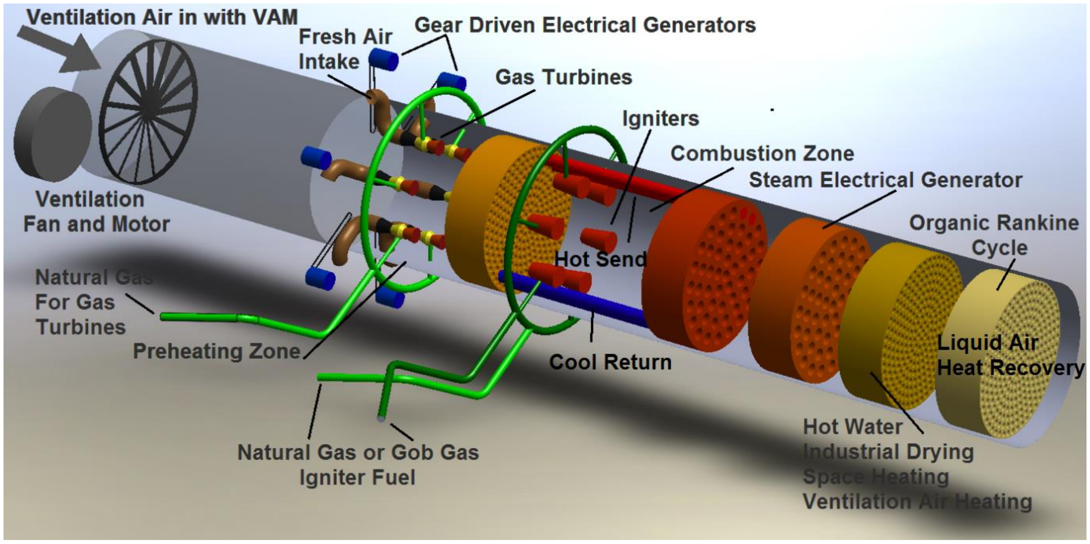


Figure 6 – The VamTurBurner©, a multi-generation system for the mitigation of VAM.

4.1. THERMAL POWER OUTPUT

The intractable problem associated with mitigating VAM and capturing the energy, is that it is a high volume air stream with a low methane content, which makes it difficult to be readily oxidized. Modeling of the combustion dynamics and chemical kinetics, of a 0.5% methane concentration, have shown that preheating to 500 K will allow the methane to ignite and undergo flameless combustion upon encountering an ignition source (33).

The benefit of this design is that an external fuel source, used to ignite the VAM, in the combustion chamber can be adjusted to provide a balancing of the heat flow. Some of the energy from the combustion chamber is directed to the preheating zone and the remainder flows through to the heat exchangers in the multi-generation system. The energy input to the VamTurBurner© arises from three separate fuel sources: the gas turbines that produce both electricity and exhaust heat, the igniters and the methane in the ventilation air. Flexibility exists in the size and number of gas turbines depending on the specific needs at the site. CMM may be used to supplement the igniters or may be added to the incoming ventilation air if it is available at the mine. Since the thermal energy from the VAM is not purchased, but appears as part of the output, the energy output is greater than that of the purchased energy. Should carbon credits become available for mitigation of the GHG, a further benefit would be realized.

5. CFD MODELING OF THE VAMTURBURNER©.

The decision as to the method of heat transfer from the combustion chamber to the preheating zone depends primarily on the methane concentration in the incoming ventilation air. The two methods considered here are heat exchangers and direct mixing of the air from the combustion chamber to the preheating zone. The heat exchanger option requires that a very low resistance to flow be introduced; thus, providing as low a pressure drop as possible while the direct mixing would introduce methane dilution. The established benchmark design constraint for the purpose of this work is the preheating temperature of 500 K for a 0.5% methane concentration (33). Further work to explore the flameless combustion dynamics and chemical kinetics of ultra-lean methane concentrations is currently in progress.

It is illustrative to examine the preheating required to maintain an adiabatic flame temperature, see Figure 7, held constant at 855 K, which is chosen as a temperature that is arbitrarily slightly higher than the self-ignition temperature of 810 K (39). The equivalence ratios of $\varphi = 0.01$ to $\varphi = 0.25$ correspond to the methane concentrations of interest of 0.22% to 1.38% respectively. It should be noted that the adiabatic flame temperature calculated by this single step method assumes a global reaction, see Eqn. 1, and over estimates the preheating required when compared to the results obtained from the LES modeling (33). For example, at 0.5% methane the preheating required to achieve an adiabatic flame temperature of 855 K, , is 632 K, whereas the result predicted by LES is 500 K (33).

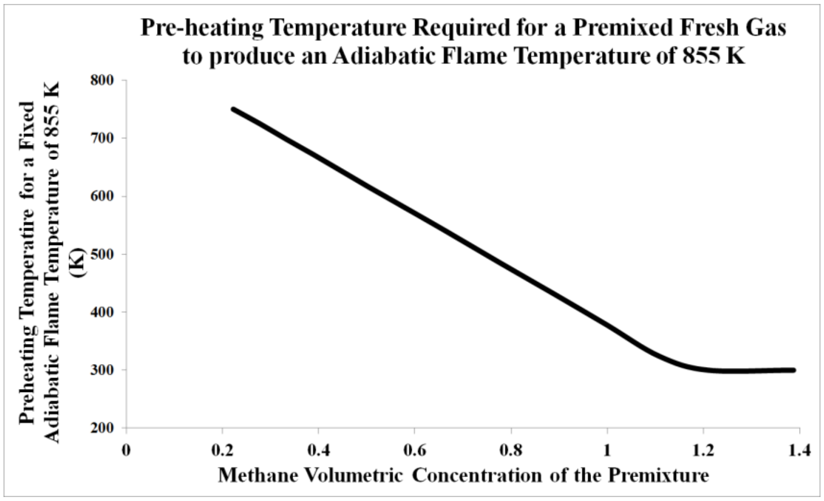


Figure – 7 Preheating temperature required to produce an adiabatic flame temperature of 855 K.

As the methane concentration increases, the preheating required is reduced until the initial temperature of 300 K produces an adiabatic flame temperature, T_2 in Eqn. 2, of 855 K at a methane concentration of 1.165%; therefore, preheating is no longer required and as the adiabatic flame temperature increases, with increasing methane concentration, the thermal energy output increases correspondingly. The molar specific heat capacity C_p^m corresponds to the value for the given species at the temperature of that species, Q^m is the molar heat of the reaction, **a** = 3.26 the nitrogen fraction in air and since the adiabatic flame temperature was calculated for a lean mixture φ is less than unity..

$$CH_4 + 2(O_2 + aN_2) \leftrightarrow CO_2 + 2H_2O + 2aN_2$$

Eqn. 1

Eqn. 2
$$T_2 = T_1 + \frac{\left(\varphi C_p^m(CH_4)+2C_p^m(0_2)+ 2aC_p^m(N_2)\right)(T_1 - T_o)+ \varphi Q^m}{\left(2\varphi C_p^m(H_2O)+ \varphi C_p^m(CO_2)+ 2aC_p^m(N_2)+1(1-\varphi)C_p^m(0_2)\right)}$$

As an example consider the following scenario: an incoming flow of 100 m^3/s from the upcast ventilation raise is at a temperature of 300 K with a methane concentration of 0.5%. The density at 300 K is 1.176 kg/m^3; ignoring the effect of the methane on the air density, and for a specific heat capacity of 1.04 kJ/kg K, the air flow contains a power of 35.46 MW with respect to a temperature of absolute zero. The densities at various temperatures are calculated using the ideal gas law and the specific heat capacities for various air temperatures were calculated from a regression equation based on the data in the JANAF tables.To be clear no heat has been released from oxidation of the VAM, this is simply the amount of energy per unit time of the incoming air at the specified temperature. Using an off the shelf micro-turbine as an example, the Capstone C200 HZLC NZ, produces 200 kW_e at an electrical conversion efficiency of 33% and exhausts 1.3 kg/s of 553 K air. Combining nine microturbines as a single source gives a total flow of 18.27 m^3/s at a density of 0.638 kg/m^3, a specific heat capacity of 1.04 kJ/kg-K and returns a power of 6.71 MW_{th}. The number and characteristics of microturbines are variable depending on the needs at the site, in this example it is assumed that 1.8 MW_e power is desired so nine 200 kW_e units are installed. Combining the sum of the GT's flow and the ventilation air stream the resultant temperature of the mixture is 324 K. Since a value of 500 K is desirable for the preheated airflow containing the methane at 0.5% a calculation of the amount of energy required to raise the temperature of the airflow from 324 K to 500 K will confirm that sufficient thermal energy is available and provide the basis for the fuel mass flow that is needed from the igniters, assuming the VAM is fully oxidized. The mass flow of the combined GT exhaust and ventilation air is 129.3 kg/s at a temperature of 324 K, which results in a power of 42.2 MW_{th}. The amount of power available in the VAM upon full oxidization is calculated based on a fuel calorific value 55.5 MJ/kg for methane. A 100 m^3/s ventilation flow with a 0.5% methane concentration converts to a methane mass flow of 0.34 kg/s and using a methane density of 0.68 kg/m^3, 18.7 MW_{th} of thermal power is released if the methane is fully oxidized. In order to create a gas flow at 500 K by mixing combustion products and the 324 K airflow some reasonable temperature for the combustion products must be determined. Since the temperature of the combustion products varies, depending on the methane content in the ventilation air and the amount of fuel flowing through the igniters, numerous possibilities can be considered. By selecting a volumetric flow of combustion products equivalent to the volumetric flow of incoming ventilation air and GT exhaust gas mixture the temperature of the combustion product air flow required was found to be 945 K. The 324 K, GT plus ventilation air stream has a density of 1.089 kg/m^3 and the 945 K combustion products airflow has a density of 0.373 kg/m^3; thus, the mass flows are 128.85 kg/s and 44.07 kg/s respectively and the combined mass flow rate is 172.92 kg/s. An adiabatic flame temperature of 945 is achieced from a 500 K airflow with an equivalence ratio of 0.17, which corresponds to a methane concentration of 0.935%. A flow of 172.92 kg/s at 500 K results in a volumetric flow rate of 244.95 m^3/s and if it is 0.935% methane then mass flow of methane is 1.557 kg/s. Since 0.34 kg/s exists in the incoming ventilation air stream an additional 1.27 kg/s is required to meet the energy requirements for operation at 0.5% VAM concentration. The total power output of 71 MW is derived from the remaining 128.85 kg/s of airflow at 945 K that has not been redirected to the preheating zone. The reader is reminded that the adiabatic flame temperatures calculated here are based on a global reaction and in view of the results of the LES modeling provide an overestimate of the preheating required. The work in progress on the chemical kinetics and combustion dynamics of ultra-lean methane mixtures is expected to show that the lower preheating temperatures are required; thus, less fuel flow in the igniters will be needed to balance the system.

Having considered the preheating requirements, a brief discussion of the heat exchanger option is followed by a more detailed discussion of the direct mixing of the combustion products to mix with the incoming ventilation air.

5.1. USING A HEAT EXCHANGER FOR PREHEATING

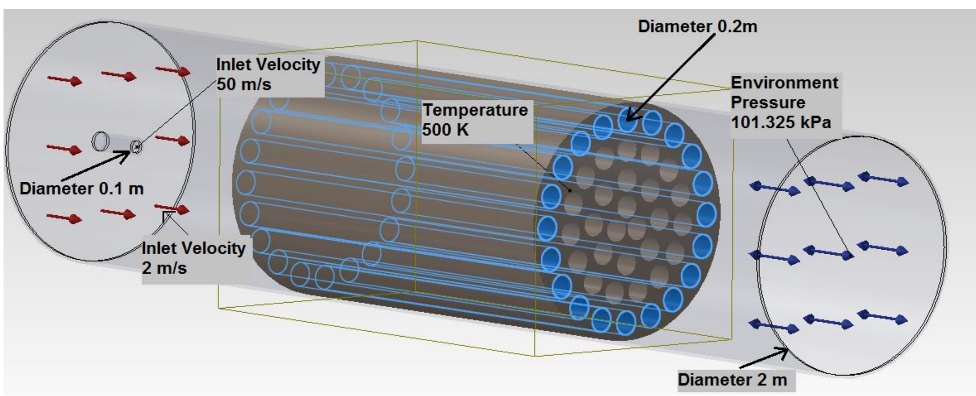


Figure 8 – Simulation of the pre-heating zone, a gas turbine exhaust interacting with a ventilation air stream with a heat exchanger, simulated by maintaining a constant surface temperature of 500 K, on the 0.2 m diameter tubes.

In Figure 8, the geometry and boundary conditions for a localized model of a single gas turbine are shown. This aspect of the CFD modeling was undertaken to establish the characteristics of the GT exhaust and ventilation air stream interactions. Additionally to provide an initial insight into the feasibility of using a heat exchanger versus directly mixing with the combustion products to preheat the ventilation air stream prior to it entering the combustion chamber. The purpose of transferring heat from the combustion chamber to the preheating zone is to satisfy the key design constraint, that the air entering the combustion chamber is at least 500 K for a 0.5% methane concentration prior to encountering the igniters. This initial CFD modeling provides an insight into the physical dimensions of the heat exchanger, which are a determining factor in calculating the cost. For the purposes of this particular model, the heat exchanger can be simulated by a constant temperature surface, to save computation time, because at this point only the dimensions of the heat exchanger are of interest, rather than the dynamics of the internal flows. The model is scaled down such that a single GT is contained in a 2 m diameter tube, which further reduced computation time.

The boundary conditions, shown on Figure 8, are typical of the assumed values used for the majority of the modeling scenarios, that is the exhaust air from the 0.1 m diameter GT exhaust outlet has a velocity of 50 m/s and a temperature of 700 K. The ventilation air stream enters the preheating zone at 2 m/s in a 2 m diameter tube. By modeling subsections of the VamTurBurner© the computation time is significantly reduced. The combustion chamber follows this section and the primary heat exchanger at the output stage follows the combustion chamber, see Figure 6. The initial conditions for each subsequent stage are derived from the output of the previous simulation.

A typical result of the CFD study based on the model in Figure 8 is shown in Figure 9. An isosurface of 500 K, displayed as a red sheet with a black grid pattern, is seen as a trajectory envelope at the GT exhaust and at the far right side of Figure 9 where the flow exits the simulated heat exchanger. The interaction, between the dark blue ventilation air trajectory path lines entering at the left and the GT exhaust, is demonstrated by the lighter blue air stream signifying an increased temperature. The increase in the local turbulence of the ventilation air stream is elucidated by the observed disruption of the flow trajectories. The temperature of the airflow exiting from the pre-heater section, simulated by a heat exchanger at constant temperature, is near 500 K.

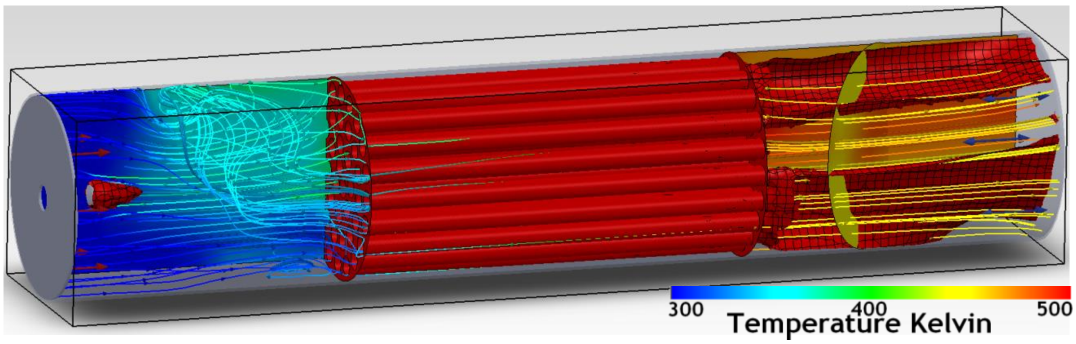
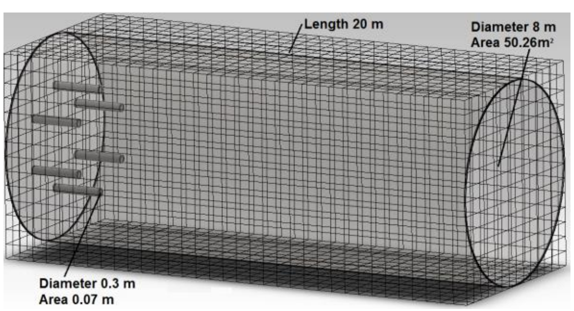


Figure 9 – Results of a typical simulation of the flow from a gas turbine interacting with a ventilation air stream.

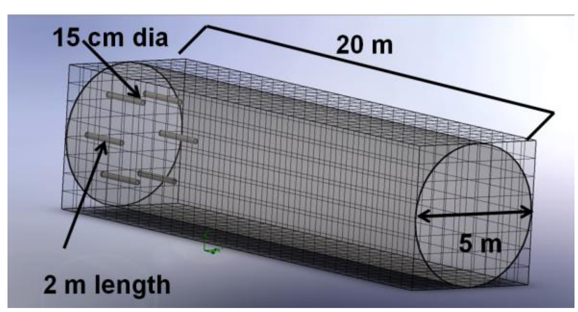
The mixing in the preheating section is an essential element of the VamTurBurner© design. Several CFD models were used for the comparison of heat exchange systems to recirculation of combustion products to the preheating zone. The results suggest that recirculation is a more economical design, for the preheating of the incoming ventilation air containing the methane, than a heat exchange system operating between the two airflows. This is an assumption based on the difference in the engineering and construction costs of a heat exchanger versus a reverse airflow system. The caveat is a concern over the dilution of the incoming ventilation air, which must contain enough methane to provide sufficient heat to the system. The combustion dynamics and chemical kinetics of ultra-lean combustion is currently the subject of continuing research.

5.1. REDIRECTING COMBUSTION PRODUCTS AND MIXING FOR PREHEATING

As can be seen from Figure 9, the mixing of the gas turbine exhaust and incoming ventilation air stream does not provide a uniform temperature distribution prior to entering the heat exchanger. Given that mixing of three airflows is required, the GT exhaust, the ventilation air stream and the combustion products redirected from the combustion chamber it is beneficial to introduce all three at the same point to promote the maximum turbulent mixing to cause as uniform a temperature distribution as possible. A series of CFD models were studied to discover the conditions required for the maximum mixing over the shortest length. Examples of the models and some sample results are presented below in Figures 10 and 11 respectively.



(a)



(b)

Figure 10 – Examples of the models for the study of GT ventilation air interactions (a) 20 m long by 8 m diameter with 30 cm diameter GT, (b) 20 m long by 5 m diameter with 15 cm diameter GT.

In Figure 10, selected results of the flow studies to determine the most appropriate geometry and deflection disc size are shown. This is a preliminary CFD modeling sequence prior to the CFD modeling involving the introduction of the combustion products. This concept requires a feedback sensor system, to monitor the temperatures and flows, to be able to respond to changes in methane concentration, adjust the fuel flow of the igniters and many other controls that will not be designed at this time. Suffice to say that the preheating curve, shown in Figure 7, illustrates that the system must be able to respond to changes methane concentration.

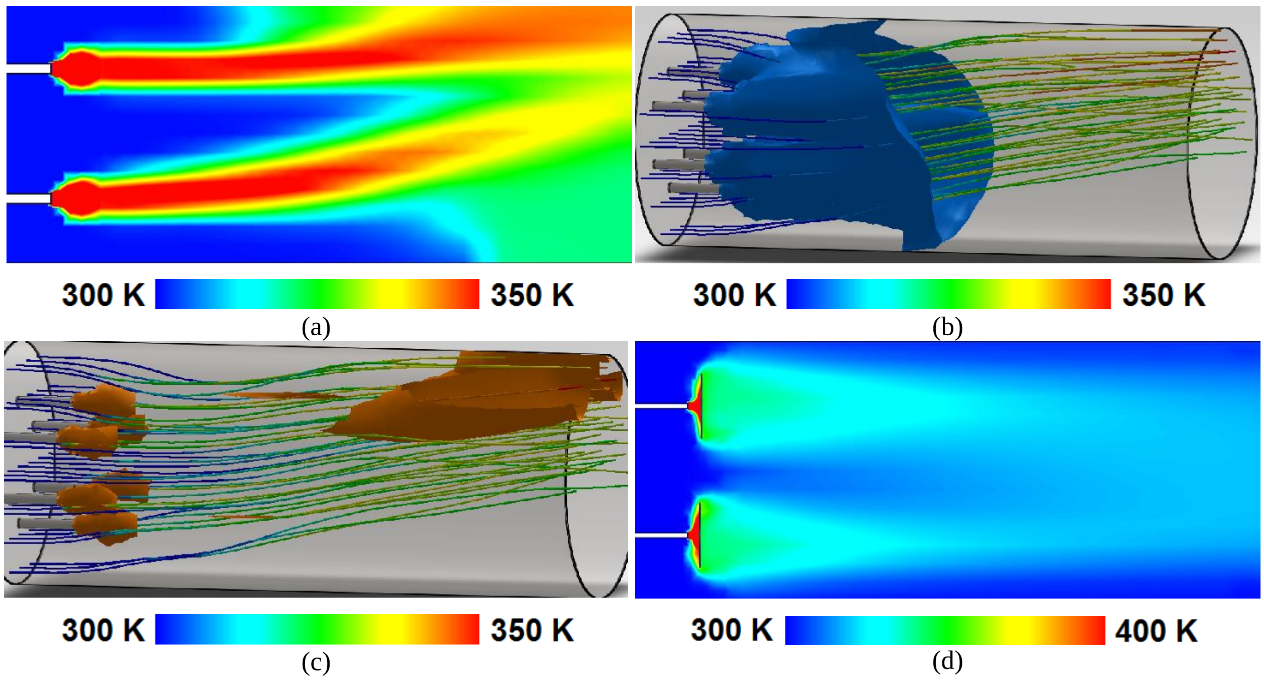


Figure 11 – Selected results of modeling the interaction of the GT exhaust and incoming ventilation air stream. (a) Side view cut through the center, the GT exhaust flows through the ventilation air stream with little mixing, but rises as the flow proceeds down the ducting. (b) 310 K isosurface with flow trajectories (c) three dimensional 330 K isosurface with flow trajectories shows the heat concentrates upwards. (d) Top view of a section through the center shows the influence of the addition and size of deflector discs.

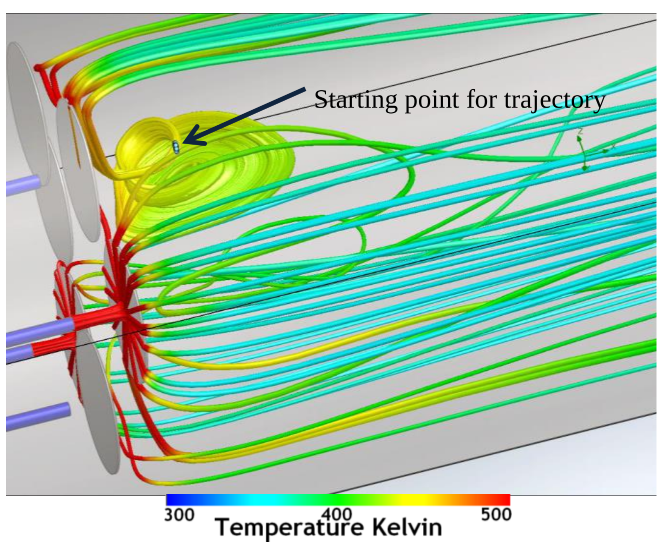


Figure 12 – A close up view of the mixing zone where the GT exhaust encounters the ventilation air.

A close up view of the turbulent mixing due to the introduction of deflection discs in the path of the GT exhaust is shown in Figure 12. The selected disc size is sufficient to force the GT exhaust to intersect the ventilation air perpendicular to the direction of the ventilation airflow resulting in enhanced local turbulent mixing. The two flow trajectories exiting from the GT exhaust, displayed in Figure 12, are considered as representative of the many that could be shown. A starting point is selected from within the turbulent mixing zone, shown by the arrow on Figure 12, to represent the activity in that volume.

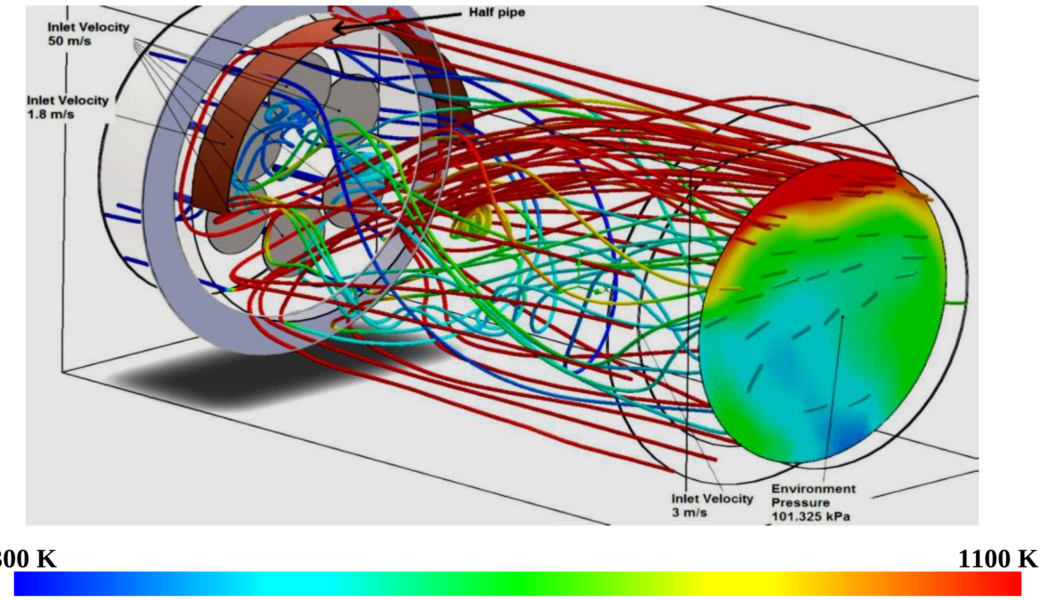


Figure 13 – Flow trajectories and temperature distribution of a representative simulation for the preheating section.

In Figure 13 the results of a typical CFD simulation are shown, one of the several simulations performed to consider a range of parameters. The temperature of the ventilation air containing the methane is set to 300 K, the diameter of the ventilation air inlet is 8 m and the ventilation air stream velocity is 1.8 m/s; thus, the area and flow rate are 50.265 m^2 and 90.478 m^3/s respectively. In other simulations with similar dimensions, the velocity of the ventilation air stream ranged from 1.8 m/s to 2 m/s; thus, inlet volume flow for the simulations ranged from 90.47 m^3/s to 100.5 m^3/s, but a ventilation flow of 100 m^3/s was frequently used as a benchmark flow for most calculations involving heat transfer and energy flow. The profiles in Figure 14 illustrate the need for the inclusion of the half-pipe, the copper colored feature indicated by the arrow in Figure 13, to direct the flow to the lower half of the preheating zone, because the high temperature combustion products rise and enter predominantly at the top at a high velocity. The cross sections in Figure 14 suggest that baffles may enhance the mixing.

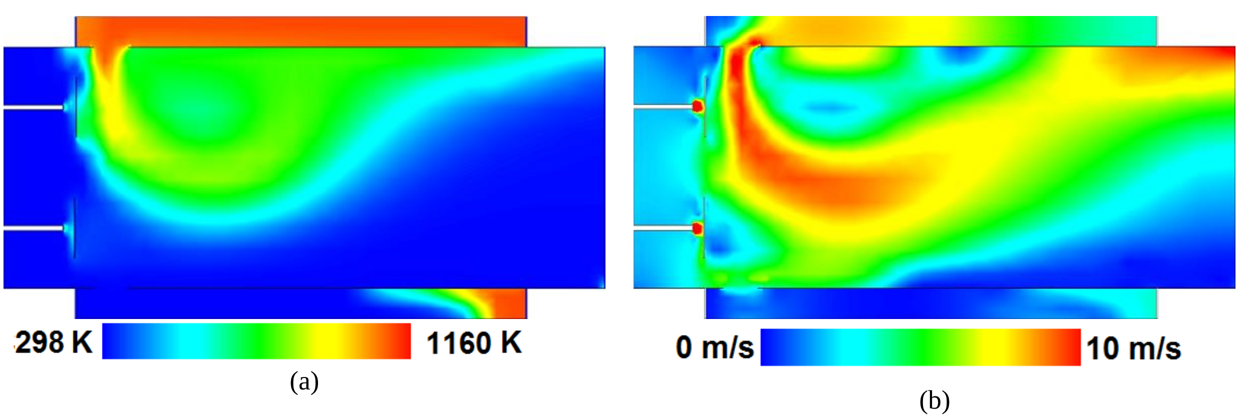


Figure 14 – Side view of cross sections through the center at 10 seconds after the initiation of flow from the high temperature combustion chamber for the (a) temperature profile and (b) velocity profile.

A representative recirculation scenario is shown in Figure 15, after several iterations, the eventual final design included four baffles, deflector discs and a half-pipe insert at the top half of the inlet port. The return flow of combustion products enters through the outer annulus at the far right, shown in gray on Figure 15 with the boundary condition, inlet velocity of 3 m/s, represented by red arrows. The return flow area is 28.27 m^2 and the flow velocities ranged from 2.5 m/s to 3.5 m/s; thus, the flow rates were 70.68 m^3/s to 98.96 m^3/s. The volumetric flow rate of the return air does not have to be less than the flow of the incoming ventilation air because the combustion products density is much less than that of the ventilation stream. The temperature of the GT exhaust ranged from 553 K to 700 K and the total flow for the all of the GT's ranged from 4.9 m^3/s to 18.27 m^3/s depending on the simulation and in some cases was based on micro-turbines available off the shelf such as the Capstone C200 HZLC NG.

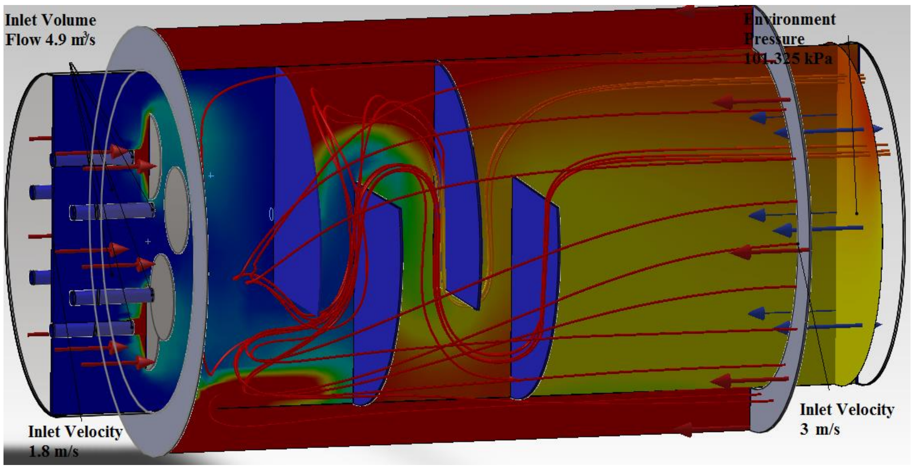


Figure 7 – Model of the pre-heating section of the VamTurBurner©with typical boundary conditions, selected flow trajectories and a cross section through the center. The temperature scale is the same as that shown in Figure 13.

The flow of the incoming ventilation air and the combustion products meet at the bottom half of the inner duct containing the ventilation flow. The concentric tube design allows the combustion products to surround the inner duct while travelling back to the preheating zone, where they mix with the ventilation air stream, before proceeding to the combustion chamber. This concentric configuration allows for heat transfer to the inner airflow through the duct wall, as such only the exterior requires insulation. The combustion products are only introduced through the lower half of the inner flow duct; see Figure 15, the red incoming air transitions to blue as it meets the ventilation flow. The co-flows proceed through the baffles to cause further mixing.

Table 4 Calculation of the temperature of the combustion products entering the heat exchanger inlet for 128 kg/s air stream at an initial temperature of 325 K

Initial Energy MJ	VAM Energy MJ	Igniter Fuel Rate kg/s	Igniter Energy MJ	Total Energy MJ	Inlet Gas Temperature K
45.5	24.15	1.0	55.5	125.11	850.95
45.5	48.31	0.9	49.9	143.71	967.60
45.5	72.46	0.8	44.4	162.32	1084.42
45.5	96.61	0.7	38.8	180.92	1201.66
45.5	120.76	0.6	33.3	199.52	1319.70
45.5	144.92	0.5	27.7	218.13	1441.41

In Table 4, the initial energy state of the air is based on an air temperature of 325 K, which represents one of the temperatures modeled for the combined flow of the gas turbine exhaust and incoming ventilation air at 300 K. The energy added to the ventilation airflow accounts for both the VAM and igniters. The igniter flow is set to 1 kg/s, at a calorific value of 55 MJ/kg, for the 0.5% VAM case and is reduced by 0.1 kg/s for each 0.5% increment of the

VAM up to 3%. The results in Table 4 are quoted in MJ, but since all flows are in units/s the power in MW is numerically identical. The temperature of the combustion products entering the heat exchanger inlet is a key variable that determines the thermal output, the example in Table 4 is intended to be illustrative of the combustion product temperature as the methane concentration and igniter fuel flow both vary. This is the first step required for calculating the capacity and size of the heat exchangers that will be required to produce the steam for electricity generation and the other thermal outputs from the combustion products flowing from the combustion chamber.

The first heat exchanger output stage of the VamTurBurner© is anticipated to be able to produce high quality steam to drive an electrical generator. The calculations of the available steam in tons/hr., presented in Table 5, are based on a ventilation airflow rate of 100 m^3/s where the energy from the methane is assumed to produce steam. The mass flow rate and conversion to tons/hr. of steam were calculated for output steam temperatures of 400 ^oC, 500 ^oC and 600 ^oC from an initial water temperature of 15 ^oC. These idealized calculations, neglecting any losses, give the maximum amount of steam that could possibly be produced at the energies corresponding to the methane concentration.

Table 5 Calculation of the Ideal steam potential for VAM concentrations from 0.3% to 2% at a flow rate of 100 m^3/s using a methane density of 0.68 kg/m^3.

	Methane		Steam Metric Tons/hr.		
VAM%	kg/s	MJ/s	600 ^oC	500 ^oC	400 ^oC
0.3	0.20	11.33	11.28	11.94	12.68
0.6	0.41	22.64	22.56	23.88	25.36
0.9	0.61	33.97	33.83	35.81	38.04
1.2	0.82	45.29	45.11	47.75	50.72
1.5	1.02	56.61	56.39	59.69	63.40
2.0	1.36	75.48	75.19	75.59	84.53

Table 6 Electrical power output and remaining energy flow produced from a mass flow of steam at 343.6 ^oC for a range of energies from the VamTurBurner© steam conversion stage.

VamTurBurner©			Steam Turbine 343.6 ^oC		Residual flow 245.8^oC
Steam Mass Flow Produced kg/s	metric tons/hr	Power Available MW_{th}	Power Out MW_{th}	Power Out MW_e	Remaining Power MW_{th}
5.40	19.44	17.02	1.03	0.98	15.99
10.50	37.80	33.12	2.00	1.90	31.11
15.30	55.08	48.25	2.92	2.8	45.33
19.95	71.82	62.91	3.80	3.60	59.12
24.45	88.02	77.10	4.66	4.43	72.44
27.27	98.12	85.99	5.20	4.94	80.79

Depending on the amount of energy contained in the VAM, the production of steam, by a heat exchanger, can provide an electrical generation capacity from about 1 MW to 5 MW with the remaining energy contained in lower grade steam or hot water. The calculations in Table 6 show the energy contained in lower grade steam until the temperature falls below 100 ^oC. In this example, the steam that is used for electricity generation is at 343.6 ^oC and the temperature of the residual, after the extraction of the energy needed to generate electricity, is 245.8 ^oC. The resultant steam is a lower quality steam that would not be well suited to electricity generation, but can supply the energy for various different uses, such as providing the hot water for use by a community, industrial drying and space heating.

6. CONCLUSIONS

Methane is a significant greenhouse gas; thus, any opportunity to mitigate methane leading to a reduction in atmospheric emissions should be capitalized upon whenever and wherever possible. Emerging economies will increase their dependency on coal for power; thus, coalmining needs to become more environmentally practical and the proponents have to be motivated to mitigate methane emissions.

A conceptual system for the mitigation of methane, the VamTurBurner©, has been presented. The adiabatic flame temperature as a function of the equivalence ratio was used to illustrate the importance of preheating of the ventilation air stream to a value commensurate with the methane concentration. Computational fluid dynamics modeling has been used to confirm that mixing of the combustion products with the incoming ventilation air stream containing the methane is capable of raising the temperature to a value that will allow for ignition in the presence of a flame or high temperature source. Further CFD modeling demonstrated that a preliminary design is capable of mixing the combustion products with the ventilation air stream to create an air stream with an evenly distributed temperature, which is essential for the combustion of the methane contained in the flow. Illustrative calculations of the potential thermal power output and steam generation capacity suggest that the VamTurBurner may be a solution that can improve the mitigation of methane while producing power.

7. FUTURE WORK

Further work to ascertain the chemical kinetics and combustion dynamics of ultra-lean methane concentrations, through an assessment of detailed chemical schemes for the oxidation of ultra-lean methane mixtures, to determine the flame stability, flame speed, pollutant predictions and auto-ignition delay time are ongoing. The results of these further studies will provide a framework within further engineering design work can be continued.

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FIGURES

Figure 1 – Three dimensional plot of the Global Distribution of Atmospheric Methane NOAA ESPL Carbon Cycle. over the last decade from the equator to the North Pole.
Figure 2 – Annual greenhouse gas emissions by sector.
Figure 3 – Percent distribution of coal production for the top 5 producers and the rest of the world.
Figure 4 – Percent distribution of VAM emissions for the top five producers and the rest of the world.
Figure 5 – Recoverable energy available after reaction sustaining fraction is removed.
Figure 6 – The VamTurBurner©, a multi-generation system for the mitigation of VAM.
Figure 7 – Preheating temperature required to produce an adiabatic flame temperature of 855 K.
Figure 8 – Simulation of the pre-heating zone, a gas turbine exhaust interacting with a ventilation air stream with a heat exchanger, simulated by maintaining a constant surface temperature of 500 K, on the 0.2 m diameter tubes.
Figure 9 Results of a typical simulation of the flow from a gas turbine interacting with a ventilation air stream.
Figure 10 – Examples of the models for the study of GT ventilation air interactions (a) 20 m long by 8 m diameter with 30 cm diameter GT, (b) 20 m long by 5 m diameter with 15 cm diameter GT.
Figure 11 – Selected results of modeling the interaction of the GT exhaust and incoming ventilation air stream. (a) Side view cut through the center, the GT exhaust flows through the ventilation air stream with little mixing, but rises as the flow proceeds down the ducting. (b) 310 K isosurface with flow trajectories (c) three dimensional 330 K isosurface with flow trajectories shows the heat concentrates upwards. (d) Top view of a section through the center shows the influence of the addition and size of deflector discs.
Figure 12 – A close up view of the mixing zone where the GT exhaust encounters the ventilation air.
Figure 13 – Flow trajectories and temperature distribution of a representative simulation for the preheating section.
Figure 14 Side view of cross sections through the center at 10 seconds after the initiation of flow from the high temperature combustion chamber for the (a) temperature profile and (b) velocity profile.
Figure 15 – Model of the pre-heating section of the VamTurBurner©with typical boundary conditions, selected flow trajectories and a cross section through the center. The temperature scale is the same as that shown in Figure 13.

Table 1 – Global anthropogenic methane by sector from three sources..
Table 2 – USA Methane emissions by coal mining activity source (U.S. Emissions Inventory)
Table 3 – Power available and carbon dioxide equivalents for mitigation of various typical methane concentrations in typical ventilation flows of a coal mine.
Table 4 Calculation of the temperature of the combustion products entering the heat exchanger inlet for 128 kg/s air stream at an initial temperature of 325 K.
Table 5 – Calculation of the Ideal steam potential for VAM concentrations from 0.5% to 3% at a flow rate of 100 m^3/s using a methane density of 0.68 kg/m^3.
Table 5 Calculation of the Ideal steam potential for VAM concentrations from 0.3% to 2% at a flow rate of 100 m^3/s using a methane density of 0.68 kg/m^3.
Table 6 Electrical power output and remaining energy flow produced from a mass flow of steam at 343.6 ^{o}C for a range of energies from the VamTurBurner© steam conversion stage.