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Process analysis of a low emissions hydrogen and steam generation technology for oil sands operations

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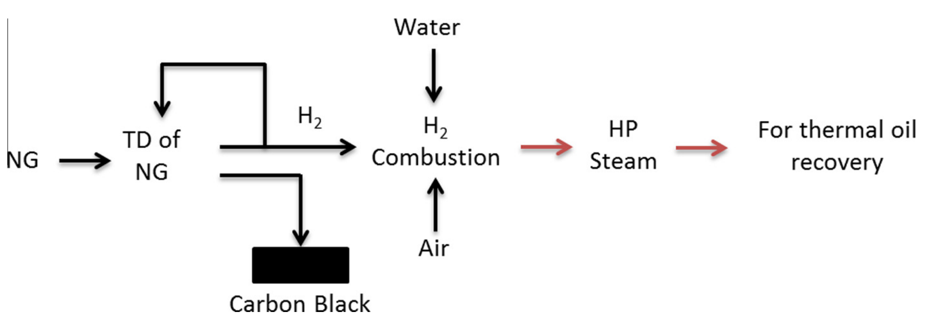
HIGHLIGHTS

- Natural gas decarbonization (NGD) coupled to bitumen recovery and upgrading.
- Hydrogen from NGD used for steam generation and bitumen hydrotreating.
- Integrated process results in a near-zero emissions.
- Valuable carbon black produced – a product that could reduce process operating costs.
- Decarbonization could reduce process efficiency by between 10% and 25%-points.

GRAPHICAL ABSTRACT



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ABSTRACT

A conceptually simple and powerful method to reduce CO_2 emissions from Alberta oil sands operations by decarbonizing natural gas (NG) fuel prior to combustion is proposed, thus removing carbon from the process up front. The natural gas decarbonization (NGD) process can be integrated with either *in situ* bitumen recovery or upgrading processes or both. The process generates hydrogen and carbon black, a stable marketable form of carbon. Decarbonizing the NG fuel to hydrogen reduces downstream CO_2 emissions and obviates the requirement for CO_2 sequestration since the carbon is stored in a solid form. The hydrogen can be used as either a fuel for steam generation or for hydrotreating. In addition, steam is generated from the hydrogen combustion reaction itself. A near-zero emissions process is achievable by using the hydrogen generated as the fuel for decarbonization. We used process modeling to assess the performance of hydrogen production and steam generation using two major process integration concepts: (i) Oxy-NG combustion integrated with the NGD process and (ii) Substantially zero emissions concept via an autothermal process using hydrogen product as the energy source for the process NGD process. Though energy penalties are incurred in the decarbonization process, we identify several potential practical process options. The proposed technology is particularly suitable for heavy oil recovery and upgrading, and fuel combustion for power generation.

1. Introduction

Steam-based heavy oil recovery processes use large amounts of hot water or steam; they are consequently energy expensive and produce huge amounts of greenhouse gas emissions (GHGs) usually emitted into the atmosphere. These energy and environmental issues arise mostly from thermal oil recovery applications where large amounts of steam are injected *in situ* to mobilize bitumen in an underground reservoir and from producing hydrogen for bitumen upgrading (hydrotreating to produce synthetic crude oil, SCO). GHGs, in *in-situ* recovery processes, are produced when fuel,

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often natural gas (NG), is combusted to generate steam. For upgrading, hydrogen is produced from steam reforming of NG. Bitumen and heavy oil deposits have been reported from over seventy countries worldwide, with the largest deposits located in Canada and Venezuela [1]. About 85% of the world's heavy and extra heavy (bitumen) oil resources (heavier than 15°API) originates from two basins: one in Alberta Canada and the other in the Orinoco Venezuela [2]. There is an increasing pressure to reduce energy intensity (invested energy per unit volume of oil produced), GHGs, and water consumption of recovering heavy and extra heavy oil.

Industrial facilities in Alberta, Canada emitting more than 100,000 tons-CO_2eq (tons carbon dioxide equivalent) per year of GHGs are required to make a 12% improvement (relative to 2007 emissions baseline) on their emissions intensity [3]. To ensure compliance to this policy, the oil sands industry must reduce the energy intensity of bitumen extraction and upgrading or pay into a technology fund at CAD$15/tonne CO_2 emitted. To put the life cycle GHG footprint of heavy oil recovery in perspective, production of SCO results in emissions ranging from 99 to 176 kg CO_2eq per barrel (bbl) (1 bbl = 0.156 m^3) of oil or 16.2–28.7 g CO_2eq/MJ whereas conventional crude oil production emits 27–58 kg CO_2eq/bbl (4.5–9.6 g CO_2eq/MJ) [4–6]. By implication, a facility producing 30,000 bbl/d oil from an oil sands process emits about 1.8 million tons/yr GHGs and is expected to make an annual GHG reduction of 251,400 tons CO_2-eq or pay $3.2 million/yr carbon tax. A recent proposal [by the Alberta Environment Minister] is even more challenging – a target of 40% GHG reduction or to pay $40/tonne to comply with the regulations. If this proposal comes on board, the industry may lose a significant amount of their income as a result. Thus, the heavy oil and oil sands industry in Alberta are poised to do more to reduce their emissions.

Over the years, several technologies, e.g. carbon capture and geological storage (CCGS) [7], have been proposed as viable options to decarbonize the oil sands energy system. In most of these processes, a pure stream of CO_2 must be obtained from stack gases of steam generators or power plants. The produced CO_2, after it has been compressed to pipeline conditions (>120 bar) can be sequestered underground in geological aquifers. However, the processes of capturing CO_2 from the flue gases, compressing to >120 bar and transporting to storage sites are energy expensive and results in significant GHG emissions. Besides the energy penalty and GHG footprint of CCGS, the integrity of CO_2 injected into underground formations, leakage risks, monitoring and occurrence of seismic disasters are key issues that must be addressed to ensure acceptance of the technology. The above mentioned setbacks to development of carbon capture and storage technology motivate research into alternative approaches that sequester CO_2 as thermodynamically stable and environmentally benign solids and as value added products that could partially offset the costs of sequestration. Two technologies that meet these requirement are mineral sequestration of CO_2 as carbonates [8,9] and natural gas decarbonization (NGD) to hydrogen and elemental carbon [10].

The objective of this paper is to show that the oil sands industry can achieve a near-zero emissions status by decarbonizing bitumen extraction and upgrading processes in a way that could be economically viable. We propose a conceptually simple and powerful process – decarbonize the NG fuel, which is the major fuel used in thermal heavy oil recovery processes prior to combustion thus removing carbon from the process upfront. This implies that steam required for bitumen extraction and the hydrogen needs of bitumen upgrading are produced by decarbonizing NG. NGD reduces downstream CO_2 emissions and obviates the requirement for CO_2 sequestration since the carbon product of the process is in a thermodynamically stable, environmental benign and elemental carbon form – carbon black. The hydrogen product can be used as either a fuel for steam generation or for hydrotreating of bitumen. In addition, steam is generated from the hydrogen combustion reaction itself. The process can even be ideally completely CO_2-free by using the hydrogen generated as the fuel for de-carbonization.

Although NGD has been studied for about two decades [10–17], no previous studies have systematically demonstrated how the application of this technology could compete or even displace existing steam generation technologies in a carbon constrained world. The focus of previous analysis was to present NGD as an alternative to steam methane reforming (SMR) process of hydrogen production [12,13]. This study is a first attempt to present a comprehensive process performance assessment of the NGD technology applied to bitumen extraction and upgrading, identifying and quantifying the associated benefits and penalties. Besides closing the identified knowledge gaps, other motivation for integrating NGD and oil sands recovery and upgrading processes comes from potentially synergistic benefits. The potential benefits include (i) significant reduction in carbon emissions, (ii) carbon emissions are permanently fixed as a valuable, marketable solid product, carbon black, (iii) carbon black byproduct presents an economic opportunity that could significantly offset the incremental energy costs of the process, making the process competitive with the conventional processes, and (iv) water generated from hydrogen combustion improves the water consumption footprint of bitumen recovery process by eliminating the need for make-up water. The carbon black could be combusted as a source of CO_2 for enhanced oil recovery.

We modeled the integrated NGD and oil sands processes using ASPEN PLUS® software. The modeling results were used to compute the overall material and energy balances, and CO_2 emissions of the integrated processes. We assessed the application of NGD to oil sands processes and associated carbon reduction benefits, energy penalties and process efficiency losses. The results from this study are compared with those of the conventional practice for steam generators (once-through steam generators) and for hydrogen production using steam methane reforming (SMR) of NG – the business as usual (BAU) cases. The process efficiency losses are calculated as the percent-points (%-points) loss in efficiency with reference to the BAU case.

2. Energy requirements and emissions of heavy oil recovery processes

Thermal steam-based oil recovery processes such Steam Assisted Gravity Drainage (SAGD), Cyclic Steam Stimulation (CSS), or recovery processes that start with steam injection (e.g. *in situ* combustion) use large volumes of water in the form of steam, to deliver heat to underground reservoirs to mobilize bitumen. Schematics of the SAGD and CSS are shown in Figs. 1 and 2, respectively. The injected water is often produced back to the surface with the mobilized oil and is then processed by water treatment and reheated to hot water or steam and re-injected into the oil formation. The typical injected steam-to-oil ratio is equal to three or higher volumes of steam (expressed as cold water equivalent, CWE) to one volume oil, i.e. >3 m^3 steam (CWE) per m^3 oil. In most operations, up to about 5% of the steam injected into the reservoir is lost to the reservoir or during water treatment operations. In some cases, the reservoir produces more water than is injected in the form of steam.

The generation of wet steam is accomplished by combusting fuel, which in most operations is NG (typically >95% methane). As a result of combustion, large amounts of CO_2 are typically emitted into the atmosphere. Steam-based recovery processes such as SAGD and CSS, at a steam-to-oil ratio (SOR) equal to ~3 m^3/m^3 produce ~0.6 tons of CO_2 is emitted per m^3 oil produced (see Fig. 3).