How will carbon emissions regulations revise energy conservation economics?

Including the cost of carbon in refinery project economics has the potential to convert previously marginal energy projects into more attractive options

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A program directed at reducing greenhouse gas (GHG) emissions is garnering higher interest by US public policy makers. This is evident by the House of Representatives passing *The American Energy and Security Act (H.R. 2454)* in June 2009. The US EPA is actively evaluating avenues in which the Clean Air Act can be used to reduce GHG emissions based on its determination that these substances (GHGs) are an endangerment to human health and welfare.

In *H.R. 2454,* individual refiners would be responsible for GHG emissions from their manufacturing operations plus the emissions from the combustion of the fuels sold by the refinery. These total emissions represent about 35% of the total US GHG inventory. However, in *H.R. 2454* the refining sector is given 2% of the available emission allowances per year until 2025. Result: Refiners will be required to purchase or to find offsets for over 90% of their regulated GHG emissions.

In this potential carbon constrained economy, significant incentives to implement energy conservation projects that are marginal or uneconomic based only on the value of fuel savings will be investigated. In this article, several case studies will be presented in which refinery energy conservation options will be considered with the economics for GHG emissions reductions. A sensitivity analysis on the value of the GHG allowances will be included in the economic evaluation.

Background. GHGs are generally defined as the total of six compounds, the main contribution being from energy-related carbon dioxide (CO_2) produced by combusting fossil fuels.

Of the annual GHG allowances available in the proposed Waxman-Markey cap-and-tradebill, only 2% of the available emissions will be allotted to the refining sector. This compares to about 35% of the total US GHGs that are actually emitted during the refinery manufacturing process and subsequent combustion of fuels by the transportation sector. As a result, refiners will incur significant expenses to reduce manufacturing GHG emission and to purchase additional allowances required to comply with the cap-and-trade rules.

Other regulatory approaches if stationary sources are being evaluated by the EPA. This consists of mandatory reporting of GHG emissions, and a proposed rulemaking that will require best available control technology (BACT) of GHG emissions for Title V and PSD Permits. In the absence of federal legislation, regional cap-and-trade markets have been established, as shown in Fig. 1.

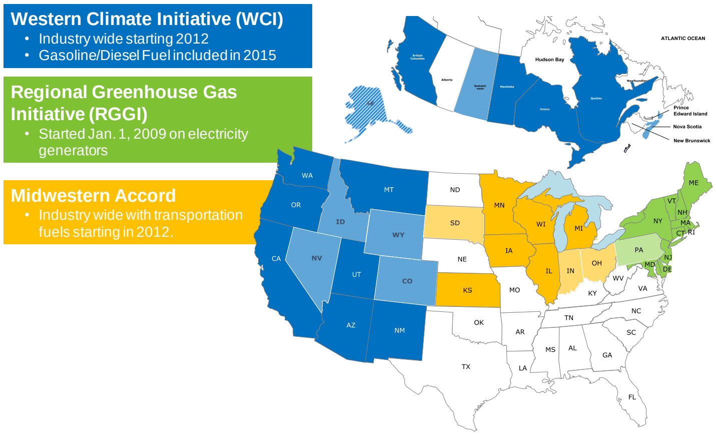

Fig. 1: Regional Climate Initiatives

Case Studies. A 150,000-bpsd (150-Mbpsd) notional refinery will be used to demonstrate the magnitude of GHG emissions and potential energy efficiency projects. Arab Medium crude was selected as the basis. Hydrogen is supplied from an onsite generation facility and a catalytic reformer (CCR). Gasoil upgrading is via a cat-feed hydrotreater and fluid catalytic cracker (FCC). Resid upgrading is achieved via a delayed coker. It is also assumed that flare-gas recovery has already been installed. The notional refinery produces these products:

- 8.4 Mbpsd liquified petroleum gas (LPG)
- 78.8 Mbpsd gasoline
- 14.8 Mbpsd jet fuel
- 43.0 Mbpsd ultra-low sulfur diesel (ULSD)
- 3.4 Mbpsd No. 6 Fuel Oil
- 1,260 ton/day coke

Fig. 2 shows the GHG emissions for the notional refinery. Emissions from the combustion of transportation fuels sold by the refinery make up 80% of the potentially regulated emissions. Emissions generated from co-products (coke and LPG) are another 10%. Only 10% of the emissions result from the refinery manufacturing process.

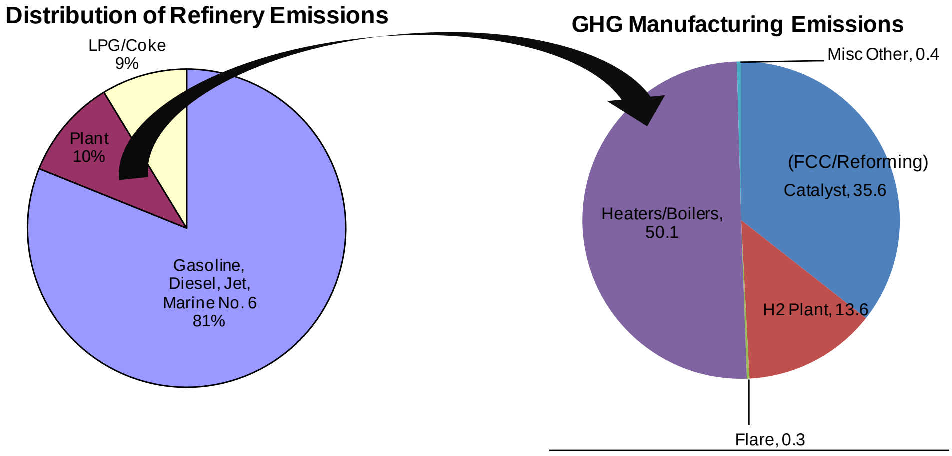

Fig. 2: Notional refinery GHG emissions.

Incremental fuel for the refinery is assumed to be supplied by natural gas. It is assumed that GHG changes in electricity consumption related to offsets are compared to a coal-fired power plant. The refinery is assumed to operate 8,400 hr/yr. Energy prices are assumed to be $5.50/MMBtu for natural gas on a LHV basis, $7.70/1,000 lb of steam and $0.07/kWh of electricity. The target internal rate of return (IRR) for plant energy conservation projects is assumed to be 20%. The energy conservation projects under review are:

- Revamp crude preheat exchange train to increase the crude heater inlet temperature
- Add combustion air preheat to fired heaters
- Replace the vacuum tower steam ejectors with a liquid-ring compressor
- Revamp the diesel hydrodesulfurization (HDS) hot feed with additional steam generation
- Install power recovery from FCC regenerator hot flue gas.

A review of the economics over a range of GHG emission prices is provided for each case.

Crude Heater Inlet Temperature. For this case, it is assumed that the crude unit was originally sized for 110 Mbpsd of feed and achieved a heater inlet temperature of 500°F. Over time, the crude rate has increased to 150 Mbpsd by minor revamps with no changes to the preheat exchange network. The existing preheat train uses four pumparounds (PAs) from the crude tower and two PAs from the vacuum tower. All side-cut products from the crude and vacuum tower are cooled against the crude feed including the vacuum tower bottoms (VTB). Fig. 3 is a summary flow sheet of the current 150 Mbpsd notional crude unit.

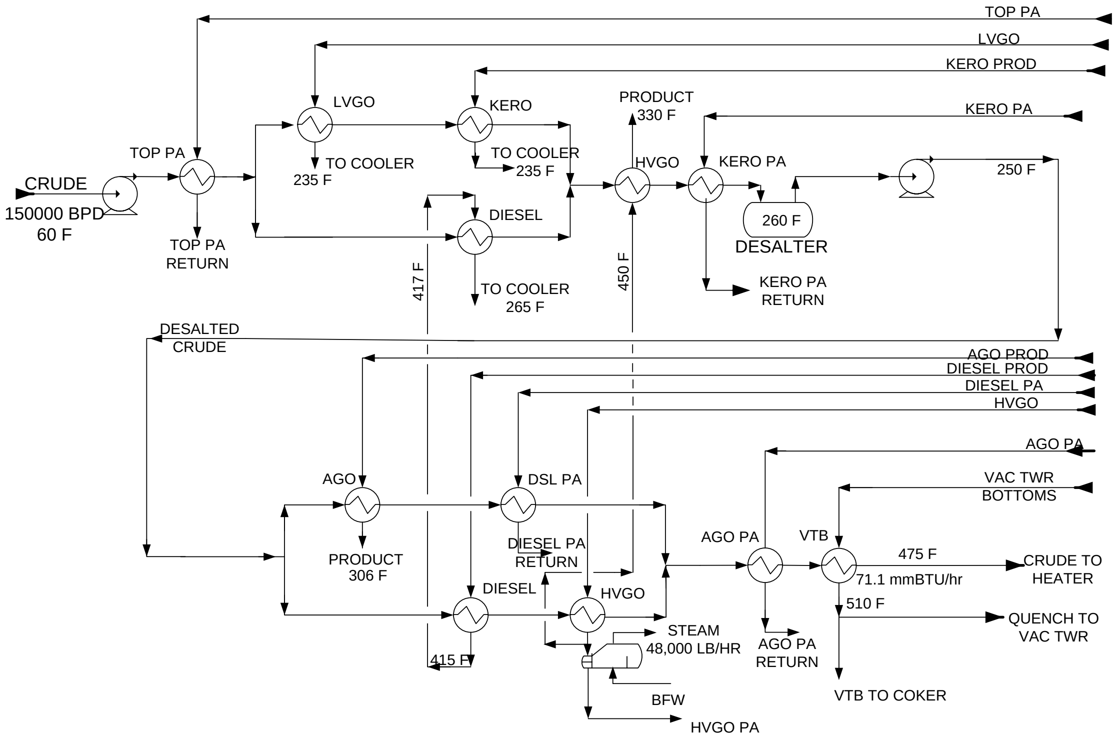

Fig. 3: Current crude preheat exchange network.

The project's goal is to increase this crude heater inlet temperature. The revamp design attempts to target thermal pinch limits to obtain maximum available duty by using the existing available hot streams.

Care is needed for any changes in waste heat steam production and subsequent changes in fuel consumption/GHG emissions at the boiler house.

Fig. 5 shows a revised heat-exchange configuration that can increase the charge heater temperature to 515°F. New exchangers were sized with appropriate metallurgy, and it was assumed that existing plot space was available for the new equipment. Since a parallel path of exchangers was selected, no changes were required for the pumps. The capital cost for this revamp was estimated to be $19.5 MM.

The IRR for GHG emissions prices from $0/metric ton to $100/metric ton is summarized in Fig. 4. A debit in steam generated in the coker due to the decreased feed temperature from the vacuum tower is accounted for in the economics. The result shows that such a revamp is marginal based on fuel savings alone. However, with the additional cost that will result from GHG emissions in a proposed cap-and-trade system, the project economics are significantly more attractive. A GHG cost of around $50/metric ton is required to achieve the 20% IRR target.

Table 1: Crude preheat exchanger network revamp results.

Heater		**Base Case**	**Revamp Case**
Absorbed Duty	mmBtu/hr	382.6	324.9
Steam in Convection Section	mmBtu/hr	36.1	28.3
Efficiency	%	87.0	87.4
Fired Duty	mmBtu/hr	481.25	404.1
Reductions			
Steam Generated from VTB	mmBtu/hr	0.0	-7.1
GHG Emissions	metric ton/yr	0	27,247

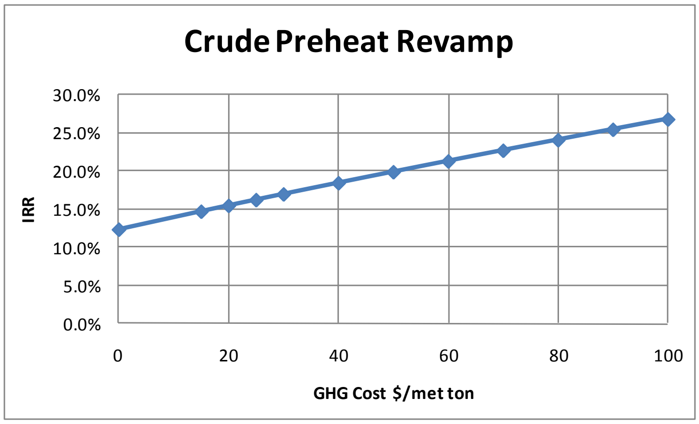

Fig. 4: Crude preheat exchange revamp economics with cost of GHG emissions included.

Installing welded-plate heat exchangers or other newer exchanger technologies could achieve an even greater increase in the crude heater inlet temperature by achieving tighter thermal pinch.

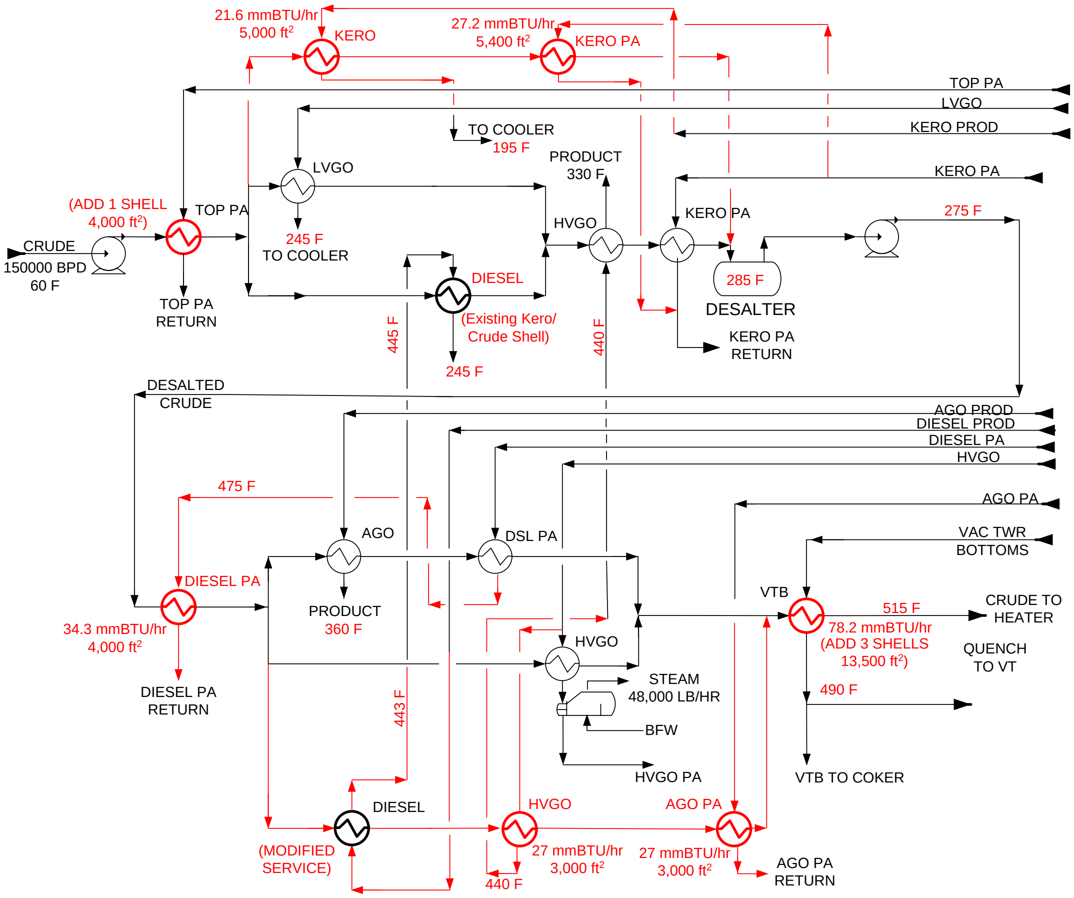

Fig. 5: Revamp crude preheat exchange network.

Combustion Air Preheat. Traditionally, most refinery heaters have a natural draft design with the process fluid flowing through both the convection and radiant sections. For larger heaters, the additional convection surface may be used for steam generation to obtain efficiencies of 88% – 89%. Conversely, for large heaters where higher efficiencies can be justified, or if incremental steam generation capability has little or no value, combustion air preheaters have been applied. Several past optimization studies have indicated that when fuel gas value is relatively high, air preheat is economically attractive for heaters above 75 MMBtu/hr absorbed duty.

Smaller heaters with older designs may have few convection rows with efficiencies of about 82%. With the additional cost of GHG emissions, these heaters may become good candidates for air preheaters. It is assumed that adding air preheat will increase the heater efficiency from 82% to 92%.

Cost data for air preheat systems equipment were obtained[1], as well as typical cost factors for installation with either revamped or new fired heaters. Fig. 6 illustrates results for installing an air preheat system to a new heater.

The results show a significant reduced absorbed heater duty that is economically viable (20% IRR) as a result of cap-and-trade requirements. At $40/metric ton, air preheat will be viable for a grassroots heater with an absorbed duty just over 20 MMBtu/hr. With GHG valued at $15/metric ton, the threshold to meet the 20% IRR target is 40 MMBtu/hr.

Fig. 7 shows the economics for a revamp of an existing heater with air preheat. The total installed cost (TIC) factor is larger for a revamp due to the amount of work required to modify the existing duct work, stack and other potential changes. Larger heaters with an absorbed duty of just over 150 MMBtu/hr absorbed duty would meet the 20% IRR target with GHG emissions valued at $15/metric ton. A sensitivity analysis for natural gas prices at $6.50/MMBtu (versus $5.50/MMBtu for the base case) on an LHV basis showed benefits at $15/metric ton would extend to heaters with an absorbed duty down to 100 MMBtu/hr.

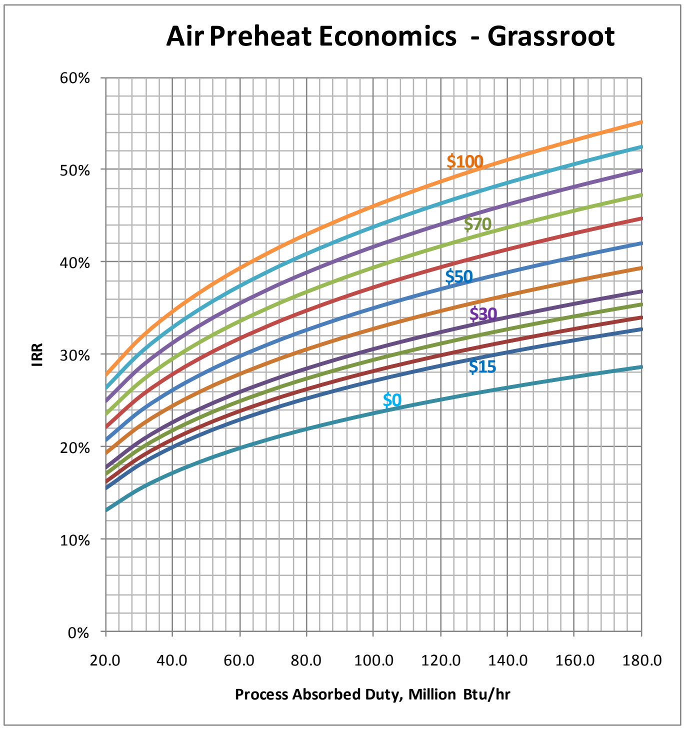

Fig. 6: Grassroot heater air preheat economics with GHG emission costs included.

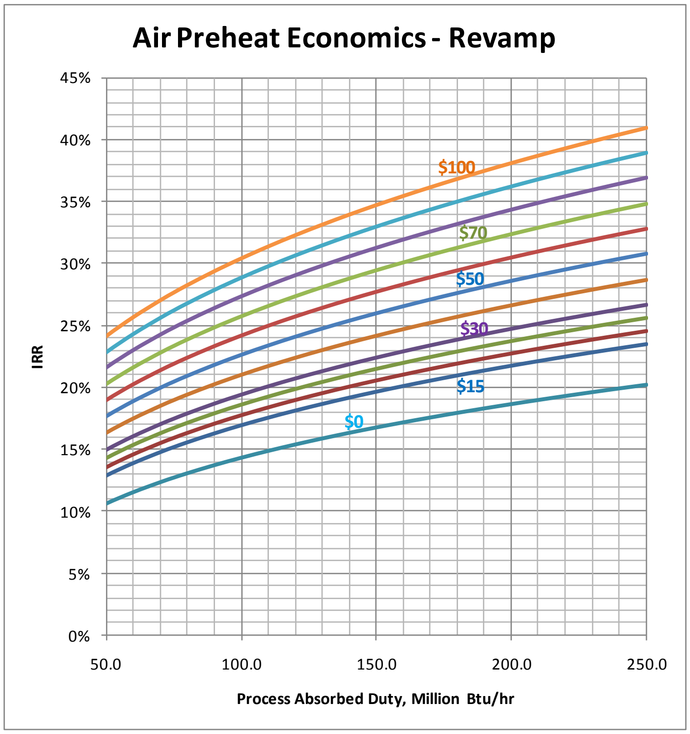

Fig. 7: Revamp heater air preheat economics with GHG emissions cost included.

Vacuum Tower Steam Ejectors. The notional refinery uses a three-stage ejector system (Fig. 8). Each ejector is coupled with an inter/after condenser with all condensed materials sent to a common seal drum. The motive fluid is 250 psig, 500°F medium-pressure (MP) steam and cooling water is available at 90 °F.

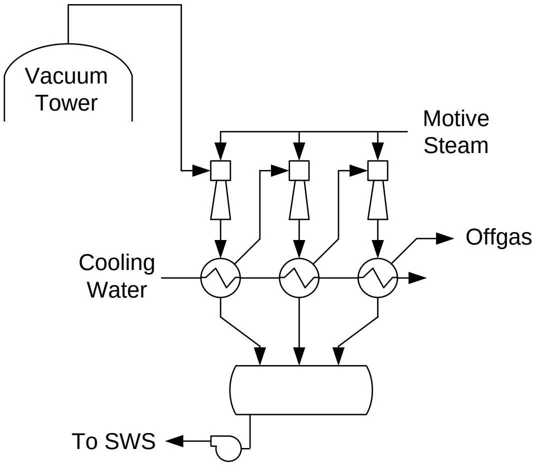

Fig. 8: Current vaccum steam ejector system.

Depending on the trade-off between the costs of steam vs. electricity, it may be economical to replace an ejector stage with a liquid-ring vacuum pump (LRVP), referred to as a hybrid system. The LRVP option has lower steam use; thus lowering GHG emission at the boilers.

The typical hybrid setup has an LRVP as the last stage of a multiple-stage system. An LRVP is not technically feasible as the first-stage. The replacement of the second-stage ejector with LRVP is not practical due to the high volumetric rate of the process gas. Table 2 summarizes the process data comparing the two cases.

Table 2: Vacuum steam ejectors revamp results.

Demand		**Base Case**	**Hybrid Case**
Steam	lb/hr	32,152	21,473
Cooling Water	gpm	2,650	2,735
Electicity	bhp	0	217
Reductions			
Boiler Fired Duty	mmBTU/hr	0	14.9
GHG Emissions	met ton/yr	0	6,649

The retrofit scope leaves the third-stage ejector and condenser abandoned in place, while the LRVP skid is located at grade. This would allow the third-stage ejector to be used when maintenance is performed on the LRVP. The seal-fluid configuration is closed-loop to minimize the seal water makeup rate. The typical skid includes seal fluid recirculation pumps, which were not needed by the notional refinery. Plot space is assumed to be available near the vacuum tower. An installed capital cost of $2.8 million estimate was developed. Fig. 9 shows the hybrid system.

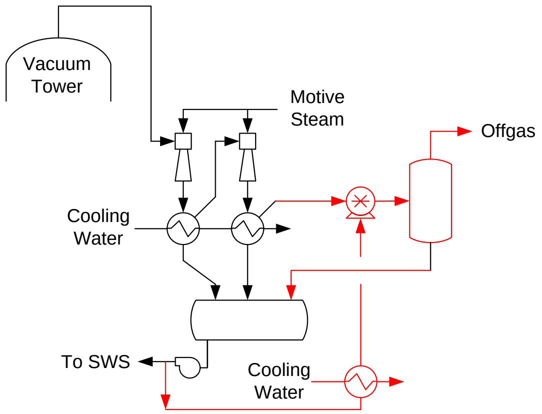

Fig. 9: Vacuum steam ejector system revamp with liquid ring compressor.

The IRR for GHG emissions prices from \$0/metric ton to \$100/metric ton is shown in Fig. 10. The result shows that such a revamp would be marginal on fuel savings alone. However, with the additional cost that would result from GHG emissions in a proposed cap-and-trade program, the project has significantly improved economics.

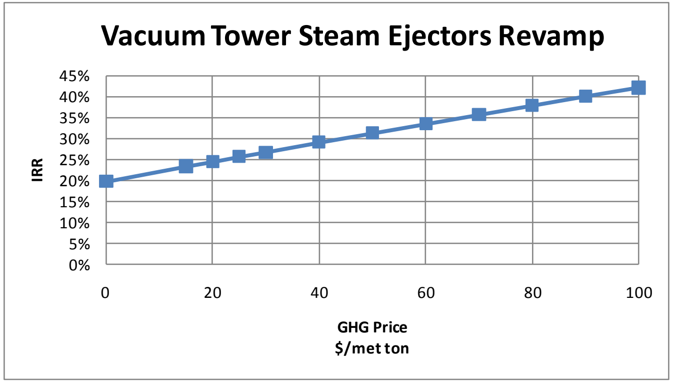

Fig. 10: Vacuum Tower steam ejectors system revamp economic with GHG emissions cost included.

Diesel HDS Hot Feed with Steam Generation. The notional refinery for this study has a diesel HDS unit that process cold diesel feed from storage to produce ULSD. The cold feed is preheated in a low-pressure (LP) stripper bottoms exchanger. The reactor effluent heats the LP separator liquid (stripper feed) and generates steam prior to being collected in the downstream flash drums. This steam generation is assumed to be economically justified during the conversion to ULSD. Fig. 11 is a schematic of the process.

For this study, generating an additional 250-psig saturated MP steam was evaluated. A promising target for heat exchange was identified by utilizing a hot unit feed to reduce the duty on the unit feed/product exchanger. The additional cooling needed for product storage can be achieved via steam generation. Table 3 summarizes the case study process data.

Table 3: Diesel HDS unit hot feed revamp results.

Generated		**Base Case**	**Revamp Case**
Steam	lb/hr	41,870	69,370
Boiler Fired Duty	mmBTU/hr	46.6	79.1
Reductions			
GHG Emissions	met ton/yr	0	14,489

A cost estimate was developed for the process revamp. In addition, 1,000 ft of new piping was included for each new feed line. The estimated installed cost is \$3.2 million; the revamp process schematic is shown in Fig. 12.

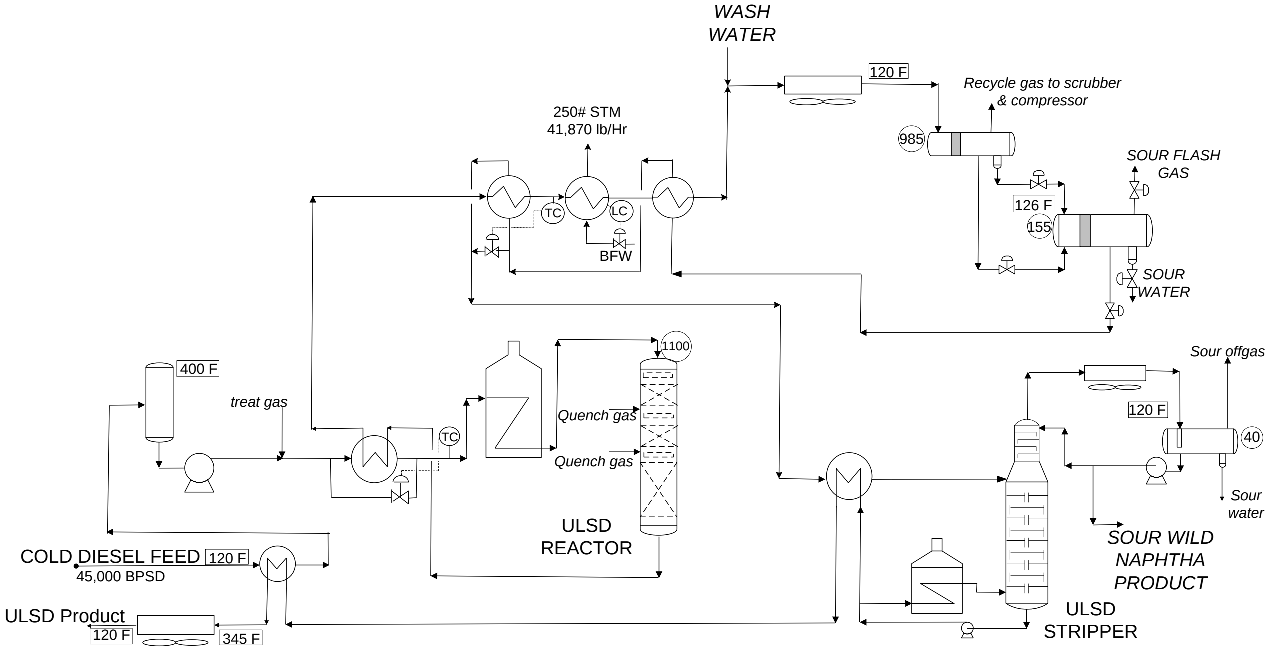

Fig. 11: Current Diesel HDS system of notional refinery.

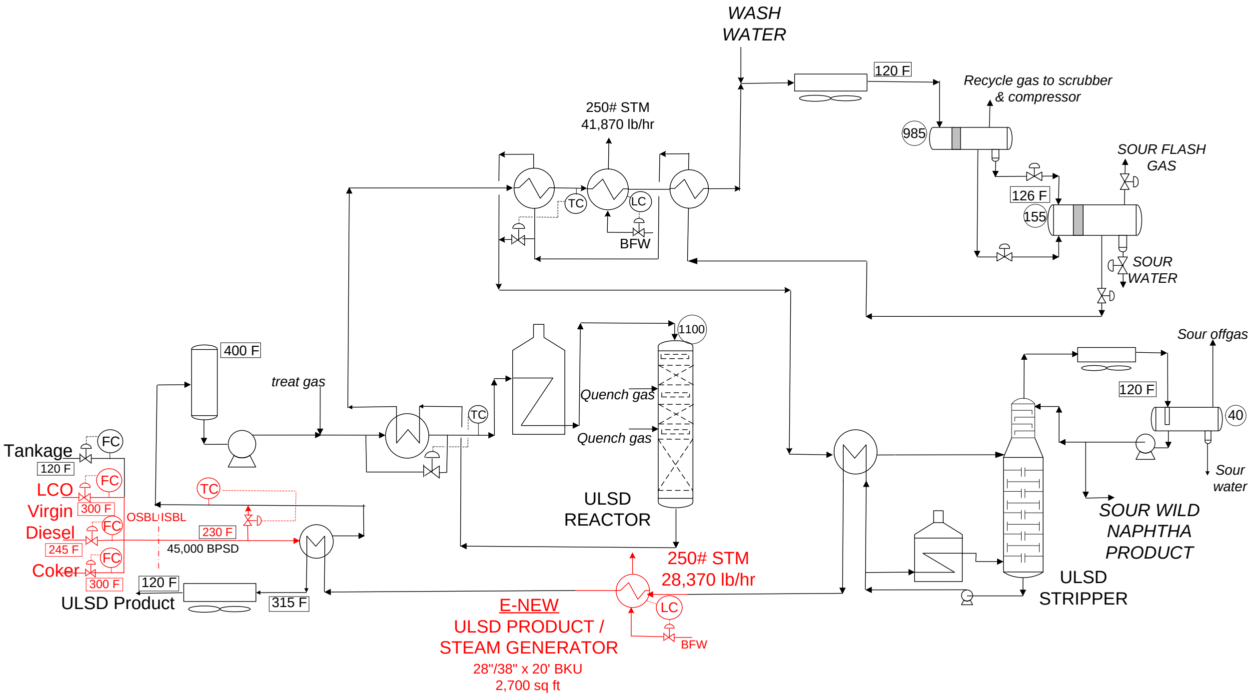

Fig. 12: Diesel HDS unit revamp with hot feed.

Results show that the economics with the assumed current energy prices would make the project economically viable without GHG credits. Fig. 13 shows that the economies are enhanced significantly when GHG emissions costs are considered.

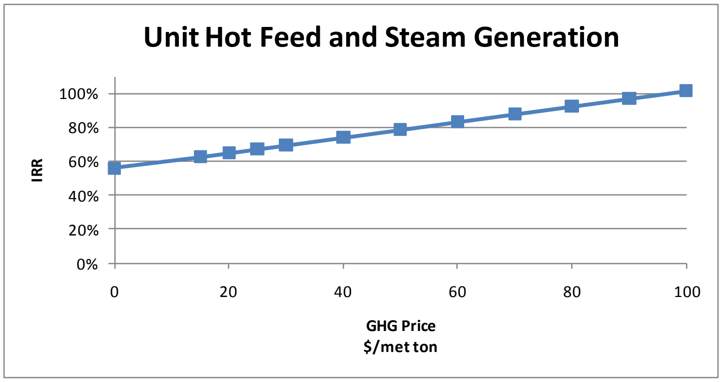

Fig. 13: Diesel HDS hot feed revamp economics with GHG emissions included.

Power Recovery. The FCC unit has a high-temperature flue gas stream from the regenerator that is typically used to make high-pressure(HP) steam. The flue gas is typically 30 psig-35 psig with a temperature of 1,350°F. The flue gas is then let down to 1.5 psig before being routed to the flue-gas cooler and the emission controls (electrostatic precipitator or wet-gas scrubber). In the flue-gas cooler, 600-psig, 600^{o}F HP steam is generated using a steam generator with an economizer and superheat section. Fig. 14 is the process schematic for this case.

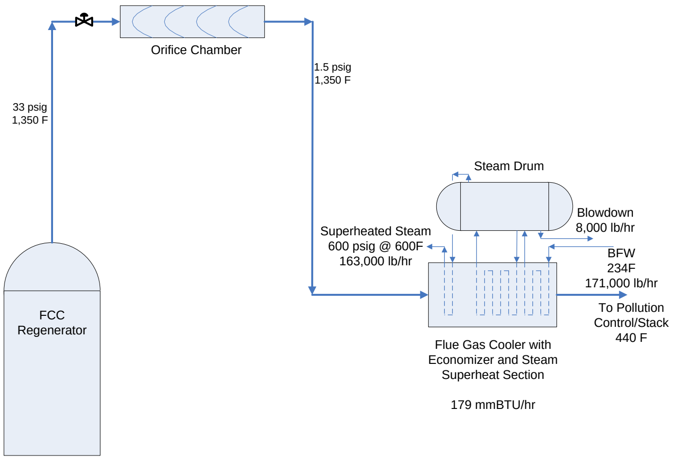

Fig. 14: Existing FCC flue gas system.

A revamp of the FCC regenerator includes a power-recovery turbine and a third-stage separator to protect the turbine from the catalyst fines. The hot flue gas is sent to the new power-recovery turbine bypassing the orifice chamber and work is extracted. The power-recovery turbine generates electrical power. The flue gas is cooled to 1,025°F at the outlet of the turbine and further cooled in existing flue-gas cooler, which will generate less 600-psig, 600°F HP steam.

For our case study, the electric power produced by the turbine offsets power generated at a coal-fired plant. Depending on the type of projects identified to be eligible for offsets under the proposed Waxman-Markey bill, credits for the reduced GHG emissions could be provided to the refinery. Table 4 summarizes the process data for this case study.

Table 4: FCC flue gas power recovery revamp results.

Generated		Base Case	Revamp Case
Steam	lb/hr	162,615	100,290
Electricity	bhp	0	24,340
Reductions			
Boiler Fired Duty	mmBTU/hr	0	-21.8
GHG Emissions Reduced			
Direct	met ton/yr	0	-20,679
Indirect	met ton/yr	0	161,387
Total	met ton/yr	0	140,708

An installed cost estimate of $40 million was developed for the revamp scope; it includes the power-recovery turbine, third-stage separator and other associated installation items. It is assumed that sufficient plot space would be available for this revamp. Fig. 15 is the process schematic for the revamp.

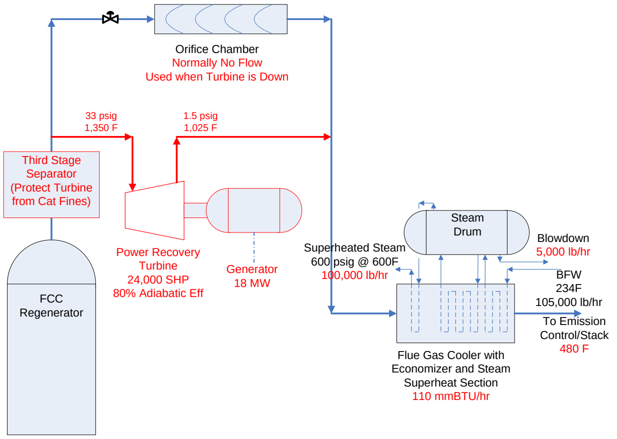

Fig. 15: FCC flue gas power recovery revamp.

Limitations in the proposed Waxman-Markey bill that reduce GHG credits received from offsets are accounted for in the economics. The IRR for GHG emissions prices from $0/metric ton to $100/metric ton for this project is summarized in Fig. 16. The results show that such a revamp would be marginal based on fuel savings alone. However, with the GHG valued at $20/metric ton, the threshold IRR of 20% would be achieved.

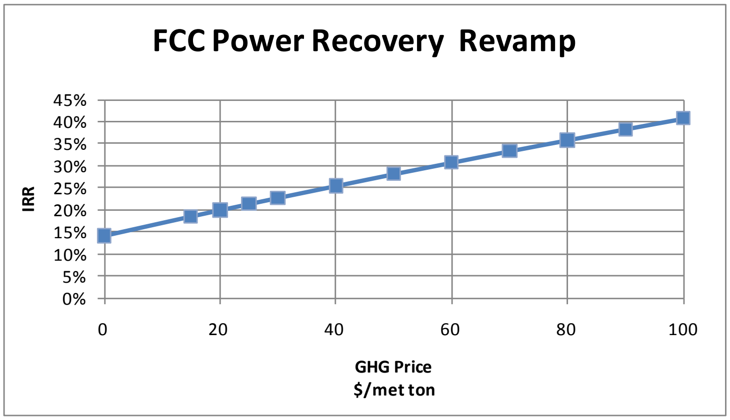

Fig. 16: FCC flue gas power recovery revamp economics with GHG emission costs included.

Summary. The presented case studies demonstrate a variety of refinery energy conservation projects that could significantly improve economics when the costs of GHG emissions from a cap-and-trade program are considered. As a result of installing all of the projects presented here, a 9.5% reduction in GHG emissions from the notional refinery is achievable. Table 5 provides a net summary of the reductions in energy use and GHG emissions.

Table 5: Summary of energy and emission reductions from proposed energy conservation projects.

Project	CO2 Reduced [1]	NG Reduced	Reduced Boiler Capacity	Power Utility Reduced	Offsets Required	Capital Cost
	metric ton/yr	SCFH	lb/hr	kWh		$MM
Crude Heater Inlet Temperature	34,161	91,758	-6,720	0	NO	19.5
Vacuum Tower Ejectors	6,649	16,376	10,679	-162	NO	2.8
Hot Unit Feed and Steam Generation	14,489	35,714	27,500	0	NO	3.2
FCC Power Recovery	140,708	-23,956	-62,325	18,158	YES	40.0
TOTAL	**196,007**	**119,892**	**-30,866**	**17,996**		**65.5**

(1) If offsets are required, CO_2 reduced includes the offsets awarded.

Observations from the various case studies show that care must be taken to evaluate all energy usage not only in the process unit of interest, but also changes in net refinery energy usage. Energy use in general will need a thorough review to ensure that all appropriate costs are included.

With the potential of offsets for power produced from coal, significant GHG reductions may be available from power recovery projects. Careful tracking of both electricity prices and available offset projects with the proposed legislation may provide some significant GHG reductions.

Various other opportunities are likely available at each refinery operation. An energy audit of the refinery operation is recommended so that the options presented, as well as additional opportunities, can be identified. The economic analysis should include the cost of GHG emissions since previously uneconomic projects may become viable as a result of proposed cap-and-trade for GHG emissions.

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1. U.S. Energy Information Administration (EIA), Emissions *of Greenhouse Gases in the United States 2008*, U.S. Department of Energy, December 2009.