Investment Expectations & Decision Making
In the Petroleum Refining Industry
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I. Introduction

At the request of U.S. Presidential Administrations and Congress, the Energy Information Administration (EIA) provides analyses used to assess proposed energy and environmental policies and to make energy forecast for the *Annual Energy Outlook* (AEO). The tool used by EIA for these mid to long term forecasts is the National Energy Modeling System (NEMS), a large-scale model of energy supply, demand, prices, and technologies. One component of NEMS is the Petroleum Marketing Module (PMM), which describes the petroleum refining industry and petroleum product transportation and marketing. In addition to petroleum refineries, the PMM includes descriptions of other transportation fuel industries, such as existing corn-based ethanol and biodiesel and potential future industries such as cellulosic ethanol and coal-to-liquid (CTL) fuels.

EIA periodically reviews the underlying assumptions and data used in NEMS in order to ensure that analyses and forecasts are meaningful and as accurate as possible. Part of this process involves seeking outside input on various aspects of NEMS. The purpose of the current review, of which this white paper is a part, is to review the investment decision making process as it pertains to the PMM, and to make suggestions as to how the PMM can more accurately predict the behavior of this sector in the future. The current methodology is summarized in the attachment to this paper. This summary is the starting point for discussion and for further development of a new or improved decision making algorithm for the PMM. Further details are available in the on-line PMM documentation [1] and elsewhere [2].

The white paper is divided into four sections: this introduction, a brief description of characteristics of the petroleum refining industry, a discussion of petroleum refinery economics and investment decision making, and finally conclusions and recommendations on where to go from here. Focus is given to providing alternatives for EIA to consider. The EIA may decide to pursue all, some or none of these suggestions, for any number of valid reasons. In any case, the objective of this paper will be achieved if it instills interest and excitement and stimulates new ways of looking at the problem at hand.

II. Petroleum Refinery Charachteristics

There are currently about 149 operating petroleum refineries within the U.S., down from a high of about 324 in 1981 [3]. These facilities transform crude oils into refined products; in particular transportation fuels such as gasoline, jet and diesel fuel. This transformation is not as simple as is often assumed by those unfamiliar with the industry. Figure 1 depicts some of the various processes involved in the refining of crude oil.

In a nut shell, the crude oil barrel is fractionated into a number of distillation cuts. Some of these cuts resemble LPG, gasoline, jet fuel and diesel. These are the refinery gas liquids (RGL), naphtha, kerosene, and light gas oil (diesel) cuts, respectively. These streams only require slight to moderate upgrading to be used as fuels.

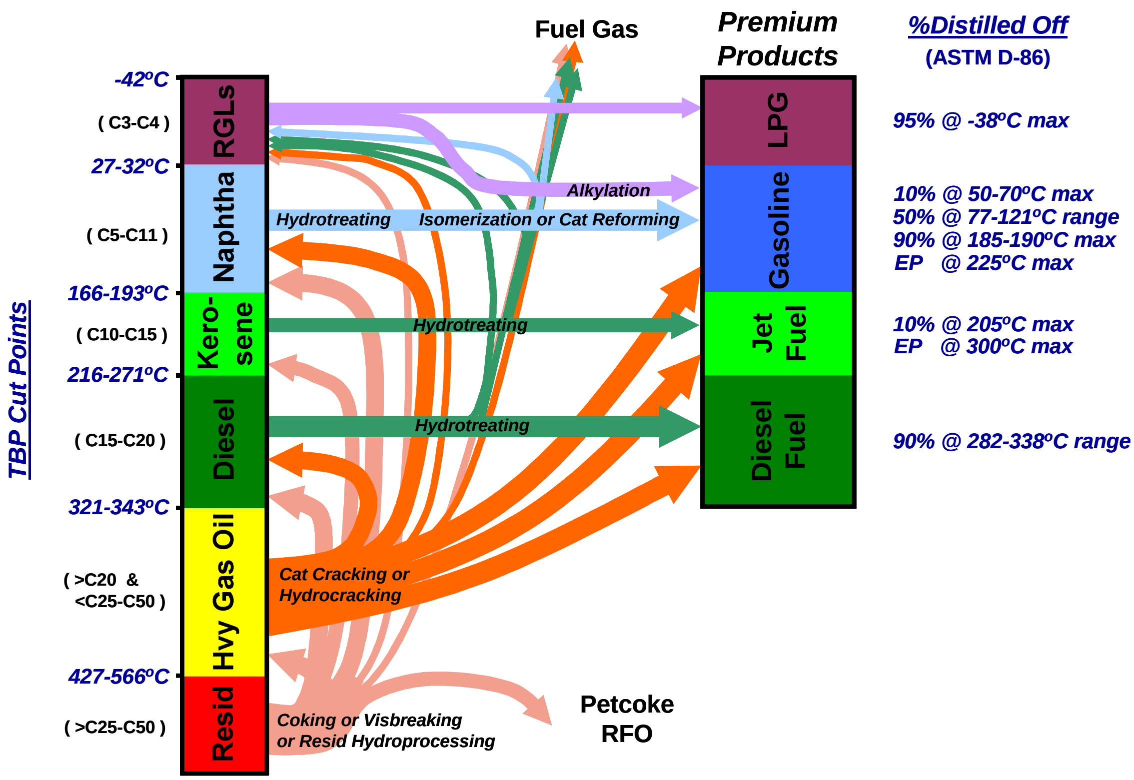

Figure 1. The Transformation of Crude Oil into Fuels

However, a significant fraction of the barrel is heavier than premium refined products. This material is transformed via cracking processes in order to maximize the production of premium products, primarily transportation fuels. Most petroleum refineries use between ten and twenty different processes for transforming crude into products.

Other than the complexity evident in Figure 1, what other characteristics of petroleum refining set it apart from other energy-related industries? The latest edition of the classic text *Petroleum Refining Technology and Economics* provides the following summary [3]:

1. Each refinery is unique and no two crude oils are the same
   - Not all refineries are created equal
   - Crude gravity is decreasing and sulfur content is increasing
   - A refinery's processing configuration evolves over time
2. Refineries are capital-intensive, long-lived, highly-specific assets
3. Petroleum refining is energy intensive, and refinery operations and products impact the environment

4. Refiners are price takers
    - Refined products are commodities sold in segmented markets
    - Product prices are volatile and correlate to crude oil prices
5. Refinery optimization involves multiple trade-offs

All of these characteristics bare some relevance to the discussion at hand. Number One implies that it can be very difficult to generalize the behavior of the industry as a whole. For example, one refinery's configuration and crude slate may make it easier for that refinery to meet existing or future fuel specifications. Thus, changing specifications would require much less investment for this refiner.

Refineries vary by size and complexity, by the types of crudes they can process and products they manufacture. These differences manifest themselves on a geographic, often regional, scale. Because of these variations, and the complexity of the petroleum refining process in general, it is not practical to model all 149 U.S. refineries individually within a model such as NEMS. *Thus within the PMM, refineries are modeled by region as defined by Petroleum Administration for Defense District* (PADD) 1 through 5. These regions roughly correspond to the U.S. East Coast – PADD 1, Midwest – PADD 2, Gulf Coast – PADD 3, Rocky Mountains – PADD 4, and West Coast – PADD 5.

Number Two is evident from the present situation in the U.S. No new "grassroots" refinery has been built in the U.S. since the late 1970s. However, the industry has been able to consistently meet increasing demand in the U.S. for refined products (since it once again started increasing after the price shocks of the 1970s and early 80s) through expansion of existing refineries and improved operating efficiency. The seemingly continuous increase in refining capacity is often referred to in the industry as "capacity creep." However, it results primarily from relatively significant increases in processing capacity at individual refineries [4], which together when aggregated across the industry, have resulted in an average growth rate of about 1.7% per year (130,000 BPD/yr). *It is investment in incremental capacity, which is the primary investment decision considered by the PMM*.

It should be noted that quoted refining capacity refers to the capacity of a refinery's crude oil atmospheric-distillation unit. This is not the only refinery unit capacity that is important. All major processing units within the refinery must be considered in order to forecast the availability and price of refined products. Table 1 lists major processes common to many U.S. refineries.

Investments have been cyclical within the industry. For the period from 2000 to 2005, capacity growth was about 17% for hydrotreating, 19% for coking, but only about 4.5% for atmospheric distillation and catalytic cracking [3]. The growth in hydrotreating was driven by new environmental regulations (Number Three); whereas, coking growth resulted from improved crude price spreads between light and heavy crudes, and to poor product margins for residual fuel oils (Number Four) [5]. The capital intensive and long-lived nature of refining assets makes them subject to considerable financial risk. The decision to invest in new refinery processing capacity is a complex one, depending both on present asset performance and expectations about the future. *The complexity of these investment decisions make them difficult to generalize, and therefore hard to analyze using simple criteria based solely on projected project economic performance as considered in the PMM.*

Table 1. Most Common Processes Found in U.S. Refineries

Atmospheric Crude Column	**Vacuum Crude Column**
Delayed Coking	**Fluid Catalytic Cracking**
Hydrocracking	**Catalytic Reforming**
Isomerization	**Alkylation**
Refinery Gas Processing	**Hydrogen Plant**
Sulfur Plant	**Product Blending**
Plant Wide Utilities	

As discussed above, petroleum refining economics is a function of many variables: plant configuration, crude oil type and price, product slate and prices, geographic location, and environmental regulations. Therefore, refinery optimization involves multiple trade-offs (Number Five) and large complex Linear Programming (LP) models are used by the industry in the decision making process. The PMM contains imbedded LP models for each of the five PADD regions modeled. *However, due to aggregation, the PMM cannot capture all aspects of operating and investment decisions.* Energy forecasting requires trade-offs, and it may not be possible to consider all decision variables implicitly.

As a final note, the PMM also contains mathematical descriptions of other transportation fuel industries, such as the existing and growing corn ethanol and biodiesel industries, and possible future cellulosic ethanol, CTL and GTL (Gas-To-Liquids) industries. Investment decisions in these industries are and will be made differently. Currently, these investments are being driven by existing or pending government regulations and mandates (Number Three); and in particular for future industries, a great deal of financial and technological risk is always present. *Investments in cellulosic ethanol, CTL, GTL and other advanced technologies are very different than the incremental refinery capacity investments normally considered in the PMM.*

III. Petroleum Refinery Economics & Investment Decision Making

Investment decisions of interest to energy forecasting are almost always made at the corporate level. Cash flows within major oil refining corporations are complex. Figure 2 is a schematic showing these cash flows.

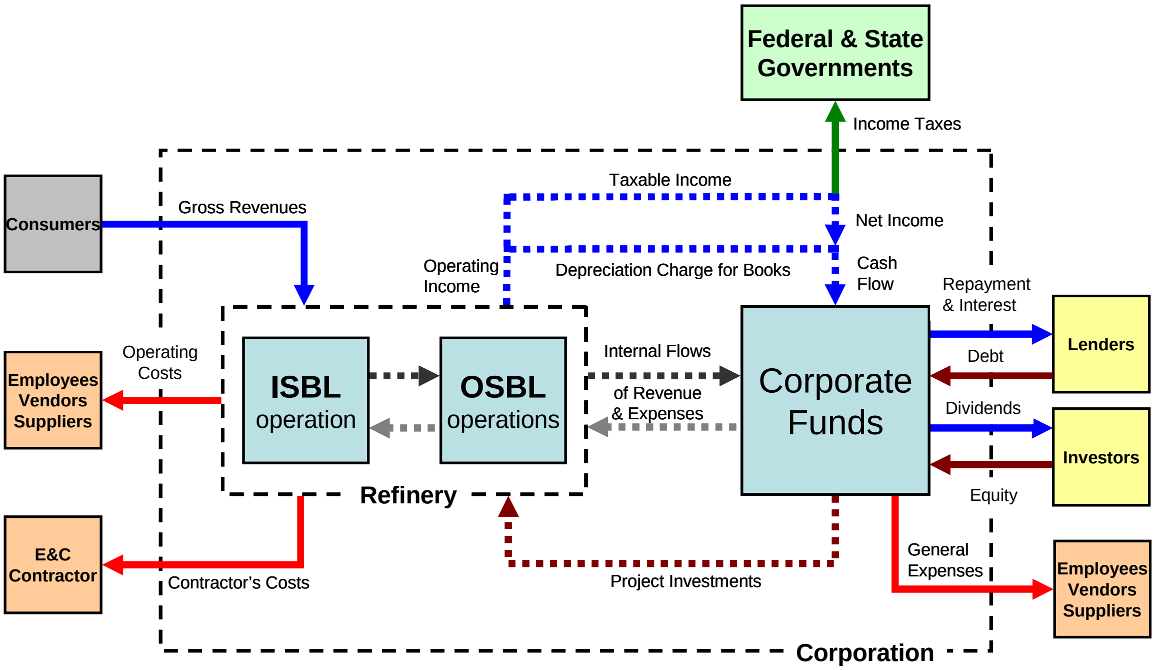

Figure 2. Process Plant, Refinery & Corporate Cash Flows

Investment decisions are subject to budget constraints of the corporation as a whole. It is typical for a corporation to specify a hurdle rate for new investments. An individual project must have a return greater than this rate to be considered; however, there are typically more good projects than there is budget for, and the investment decision usually comes down to a ranking of the best projects. *Therefore, it is the relative ranking of projects that is most important and not the absolute return on investment, which will vary based on the financial assumptions employed.*

Budget constraints not only come into play in the yearly budget cycle, but also impact decisions in future years. Refinery capital projects tend to be large and complex and can have lead times anywhere from two to five years or more. Therefore, decisions made on a project in one year may limit the capital budget in future years. Most corporations typically consider a five to ten year planning horizon for their capital budget.

For large projects, the investment decision is not a single discrete event. Typically, a project may be initiated by either refinery engineering staff or by a corporate engineering group. The initial concept will be screened internally prior to any detailed analysis. The initial engineering estimate will be precursory and subject to considerable uncertainty (40% or greater), with the first decision being either to drop the project or to proceed to more detailed analysis and cost estimating. A large project may go through three to five cycles before the final decision to construct is made and contracts are executed. The project will be reviewed and approved along the way at increasingly higher management levels. For large projects, the last definitive cost estimate will almost always be prepared by an outside engineering and construction firm specializing in this type of work. At this point, the uncertainty in the estimate should be less than about 5%[1]. *Unfortunately, energy models tend to treat this entire process as a discrete one-time investment decision.*

For most refinery projects, the technology to be employed is already proven. Therefore, the uncertainty in the project is almost always project related and a project contingency is applied during the project development phase to account for this uncertainty. This contingency will start out high and be worked down as the project scope becomes more well-defined. However, this is not the case with alternative fuels such as cellulosic ethanol and CTL/GTL.

For cellulosic ethanol, there is a great deal of uncertainty associated with the pretreatment and fermentation steps used in the process, and this uncertainty will not diminish until these processes have been commercially demonstrated. A process contingency is usually applied to the cost estimate to account for this technological risk. This contingency will not decrease during the execution phase of the project. Not until process start-up and performance testing are completed on the constructed plant will the true cost of the technology be known with any certainty. It is often assumed that the first three to five plants will be subject to this type of risk.

The situation with CTL/GTL is somewhat different. CTL and GTL technology involve a number of different but highly integrated process steps, rivaling petroleum refining in their level of complexity. All of the individual steps have already been proven commercially; however, the size and overall complexity of the process introduces a great deal of technological uncertainty. This uncertainty should also be accounted for using an appropriate process contingency.

Financial evaluation of projects is a function of corporate engineering and planning departments. The planning department has responsibility for generating short to mid-term forecasts for crude oil and refined project prices, and other costs. This information is combined with the project cost estimate in order to determine the potential profitability of a project. Refinery LP models may be used in investment evaluations, but their role is usually limited to the study of possible refinery configurations. Due to the great degree of non-linearity associated with the capital costing of equipment, other tools are used by the industry for market studies, capital cost estimating, and economic forecasting. This approach allows multiple alternatives to be examined. Transparency would be lost if only the optimal solution could be viewed and analyzed.

In recent years, the refining industry as a whole has been disciplined in its approach to project evaluation. As a result of earlier projects that led to over expansion and decreased profit margins, conservative assumptions about the future are the norm. To quote Edward G. Galante, Senior Vice President, ExxonMobil Corp [6]:

[1] Based on this view of the investment decision process, it should not appear unusual for there to be a flurry of planned investment announcements in the press when times are good, followed a string of announcements of project cancellations as cost estimates, market projections, etc. are firmed up.

> "Short-term perceptions are not sound guides when dealing with the realities of a global, highly technical, long-term, capital-intensive industry. In our long-term business, we must not cling to the perception that our course must be altered with every gust of wind that rises along the way."

The same cannot be said for the state of the current alternative fuels industry within the U.S., where over-optimism may be the norm. Within the refining industry, it is often assumed that refinery product margins will return to historical levels over a relatively short period of time, and that historical increases in product demand will persist in the short to mid-term. Alternative assumptions (*e.g.*, higher/lower oil prices) are almost always considered within an accompanying sensitivity analysis.

A number of quantitative measures of profitability are used in the refining industry. A simple rate of return may be used for preliminary planning. However, net present value or internal rate of return will most certainly be considered for making the final investment decision. Also of importance is the payback period, since this is an indicator of the length of time for which the corporation's investment is at risk, and the actual total project investment, since this can place constraints on other investment opportunities for the corporation. The industry has typically employed a hurdle rate of between 20 and 30% for refining investments. However, the industry as a whole rarely achieves this level of return, which for the period 1977-1999 averaged only about 5%. *Since the PMM is modeling the investment decision process and not the financial performance of previous refining industry investments, the higher hurdle rates should normally be used.* In some instances, the strategic importance of an investment to the long term financial growth of the corporation has been used to justify lower hurdle rates. This was the case for early investments in LNG in the 1980s and early 90s. While at about the same time, shale oil, coal liquefaction, and other alternative fuels projects were abandoned by the industry.

Capital projects may be undertaken for a variety of reasons, such as necessity ("must-do" projects), product or process improvement, plant expansion, or new ventures [7]. For the last several decades, U.S. domestic refinery projects have been primarily necessity and capacity expansion projects. Recent industry investments may be classified as:

Must-Do Projects. Must-do projects include maintenance and projects required to meet environmental, health, safety, and plant security requirements. *Other than investments to meet particular environmental regulations, must-do projects have typically not been rigorously modeled in the PMM.* These investments can be estimated as a fixed fraction of the refinery book value. It should be noted that possible future regulations related to plant greenhouse gas emissions cannot be accurately estimated by factoring, and if needed in the future, must be modeled explicitly within the PMM.

Only projects for meeting environmental regulations affecting product specifications are considered explicitly within the PMM, such as the desulfurization of gasoline and diesel fuel required by the Clean Air Act Amendments of 1990 (these could arguably also be classified as product or process improvement projects). Historically, these types of environmentally-driven projects have been executed by the industry in conjunction with expansion projects, since the incremental cost of expansion of affected units will be lower under these circumstances. Execution of these projects simultaneously also provides some engineering and construction economies and improves the overall return on investment. This type of investment scenario has been a major source of capacity creep within the U.S., and in the past this has been responsible for periods of over expansion (*e.g.* MTBE and gasoline reformulation [8]).

Clean-fuels projects typically involve some element of new technology; but in many cases, the core technology is proven and is already present within the refinery. Only incremental improvements are being made to the process, such as the addition of new or improved catalysts, or the modification of process operating conditions. A past exception, resulting from the passage of the Clean Air Act Amendments of 1990, was the oxygen content specification for oxygenated and reformulated gasolines. This requirement was met by blending ethanol or the ethers MTBE and TAME in gasoline. Some refiners chose to produce MTBE/TAME at the refinery from purchased methanol and refinery-derived butylenes and amylenes. The MTBE/TAME synthesis process was the first major refining technology to achieve wide acceptance in the U.S. petroleum refining sector since the 1960s (some of these units have since been shut down or converted to the production of isooctane). Other new technologies, such as sulfur adsorption and solid-acid alkylation have not gained wide acceptance within the U.S. These technologies compete with well-established processes such as hydro-desulfurization and hydrofluoric or sulfuric acid alkylation, respectively, and have only had some success in grassroots applications, mostly outside of the U.S. The production of “green” or ”renewable” diesel from vegetable oils and animal fats is the latest new technology to be considered by U.S. refiners, with interest being driven by recent renewable fuel standards set by the U.S. EPA.

Projects to Improve Profitability. Recently, there has been interest in projects to improve refinery profitability by increasing the price spread between refinery feedstocks and product slate. This can be challenging to accomplish since refiners have traditionally been price takers. Two examples of this approach both involve investment in bottom-of-the-barrel conversion technology [5]. Some refines have invested in bottom-of-the-barrel conversion to eliminate low-value residual fuel oils from their product slate in order to improve their profit margins. Other refiners have been able to replace part of their crude slate with lower-cost crudes of low quality (low API gravity, high-sulfur content) to improve profit margins. They have mitigated financial risks for these investments using a number of mechanisms, such as the formation of joint ventures with oil producers where the producer shares in the refinery investment, or by entering into long-term purchasing contracts that guarantee the refiner a feed price indexed to a specified benchmark, while guaranteeing the producer a long-term market. Suncor [9], Husky Energy [10] and others have these types of arrangements in place for supplying oil sands-derived bitumen and syncrudes to the U.S. Similarly, both PDVSA [11] and Pemex [12] have arrangements for marketing their heavy oil production in the U.S. *The complexity of such financial arrangements cannot be modeled explicitly in an aggregated model such as the PMM.*

While a number of technologies are available for bottoms processing, U.S. refiners have almost exclusively relied on delayed coking to convert the bottom of the barrel. Relative to other conversion options, delayed coking requires a lower capital investment, and since coking is a mature technology, the technological risks associated with these projects are low. Recently, some U.S. refiners have installed gasification units for converting the petroleum coke by-product into hydrogen, power and steam for supplying the refinery's internal needs or for sale across the fence.

Projects to Increase Capacity. Expansion projects within the U.S. refining industry have mainly been for adding incremental capacity to existing refineries. These expansions have either been achieved by de-bottlenecking existing refinery units or by adding new units within existing refineries. These new units have for the most part used existing technology common to the petroleum refining industry. So, in the context of the PMM, which only considers five regional aggregate refineries, these appear as incremental capacity additions to the base process capacities in the five PADD regions. By contrast, ethanol, biodiesel and CTL/GTL plants are clearly new ventures. As such, they are considered independent of the regional refineries, with their product sold into existing fuels markets either as a neat fuel or blended with a suitable petroleum counterpart.

Expansion projects are driven by increases in product demand and can be difficult to model accurately in the PMM, since they are influenced by factors such as product imports and by industry perceptions relative to long-term demand. However, since the U.S. is a mature market, annual increases in fuels demand have been relatively small, and *the current PMM is capable of doing a reasonable job in projecting future refinery incremental capacity expansion.* As discussed above, most of this expansion has been achieved through capacity creep, with the capacity expansion investment coupled with "must-do" environmental projects. Therefore, the investment for the expansion component of these projects is not well documented.

There have been recent announcements of major capacity additions planned a number of existing U.S. refineries [13], most notably, Marathon's Garyville refinery and Motiva's Port Arthur refinery. These are strategic investments that require a long-term outlook and involve technology and capacity additions to the existing refining complexes. While there has also been talk of construction of several new "grassroots" refineries in the U.S., these are still uncertain. Of these, Arizona Clean Fuels, LLC, is farthest along in their plan to construct a refinery near Phoenix, AZ [14]; however, they have not yet proceeded to the construction phase. Interest in the construction of new U.S. refineries is a phenomenon driven by localized product-demand growth, and these plants if built are unlikely to be a significant factor in future refinery capacity addition.

It is apparent from the above discussion, that all refiners (or their parent companies) do not view the future in the same way. Currently, some in the industry see a need to expand capacity to maintain or increase their share in an expanding fuels market. However, not all refiners see increased transportation fuel demand as unlimited. Some see government alternative fuels mandates as capping or shrinking petroleum fuel requirements in the mid-term and others, others such as ExxonMobil [15], see improved vehicle fuel economy and the introduction of hybrid vehicles doing the same thing over the longer term. While still others, such as Marathon [16], anticipate a gradual longer-term shift away from spark-ignition gasoline engines toward higher-efficiency compression-ignition diesel engines, and are investing in hydrocracking technology in order to make this shift in product slate.

New Ventures. The current interest in alternative fuels is driven by concerns related to the impact of climate change and to national security threats, and perceptions of an imminent end to the "age of oil." The run up in crude prices in recent years has resulted in higher fuel prices that make some alternatives more attractive. A number of major petroleum companies are now pursuing strategic investments in biofuels. Marathon has formed a joint venture to construct new corn ethanol plants [17], and Chevron is actively marketing and distributing biodiesel [18].

Others are pursuing new ventures in so-called second-generation biofuels. BP [19], Shell [20] and Chevron [21] have active R&D programs and collaborative partnerships for the development of cellulose-derived biofuels, such as bioethanol and biobutanol. ConocoPhillips is pursuing green diesel [22] as an alternative to biodiesel, and biomass-derived pyrolysis oils as alternative refinery feedstocks [23]. UOP [24], a major provider of petroleum refining and petrochemicals technology, is also developing advanced biofuels technology.

There are many new ventures related to alternative fuels underway outside of the petroleum industry, focused in the U.S. primarily on cellulosic ethanol, CTL and BTL (Biomass-To-Liquids), algal biodiesel, and other alternatives. Investment in these future technologies is being provided by venture capitalists (*e.g.* Khosla Ventures [25]), by major corporations outside the oil patch (*e.g.* DuPont [19]), and by government agencies (USDA and DOE). Many of these technologies are in the earliest stages of development. CTL is the most mature, but has not been commercialized outside of South Africa, and cellulosic ethanol is near-commercial, with government-funded demonstration projects anticipated to start up between 2009 and 2011 [26]. The financial, as well as technological risks, associated with these technologies are quite large. However, many of the investors in these alternatives have very different perceptions of what the future holds and what the risks might be. As Bill Wiberg, a partner at Advanced Technology Ventures has put it, "You just have to believe the end opportunity will warrant the time and capital [being invested]" [25].

In summary, alternative-fuels ventures are relying on existing or future government-driven mandates or regulations requiring the use of alternative fuels to both decrease U.S. dependence on imported oil and reduce greenhouse-gas emissions generated by the transportation sector. Therefore, considering the wide variation in expectations, it is likely that fuels investment decisions will have multiple and possibly conflicting objectives.

IV. Conclusions & Recommendations

Petroleum refineries have unique characteristics which have direct bearing on capital investment decisions. Petroleum refining benefits from economies of scale due to the capital-intensive nature of the enterprise, and refineries in the U.S. tend to be large, complex and long-lived. While the processes used in refining are common to the industry, every refinery employs only a subset of these processes, and they are integrated and operated to meet the needs of the individual refinery and the markets it serves. For these and other reasons, all refiners do not view the future in the same way, and individual refinery investment objectives will vary. One-size-fits-all approaches to investment decisions will not be able to identify all investment opportunities that are likely to be pursued in the future.

For the most part, major investments in U.S. refining have been made either to meet new regulatory requirements or to add incremental processing capacity to existing facilities. Incremental capacity expansions are typically coupled with environmentally-driven investments, and improve the refiner's return on investment. For the U.S. industry as a whole, these incremental expansions have resulted in steady and significant growth over time. Capital investments for large expansion projects are less frequent and tend to be executed counter-cyclical to environmental investments.

Refinery capital projects are subject to significant risk and must be carefully planned and executed. Multiple criteria including total investment, payback time, and return on investment are all considered. The U.S. refining industry as a whole is conservative in its approach to investing, and has been disciplined in investing both through good and bad times. The same cannot be assumed for the emerging alternative fuels industries in the U.S.

Modeling the behavior of the petroleum refining industry within an energy model such as NEMS therefore presents a challenge. Philosophically, it is desirable to keep the approach taken as simple as possible. The accuracy of the investment analysis cannot be expected to be superior to that of the input data or to assumptions employed in the PMM and elsewhere in NEMS that it is based upon. In addition, adding unneeded complexity can reduce the performance of NEMS as a whole, thus limiting other useful and needed model enhancements.

It is not necessary that the methodology employed in the PMM be the same as that used in other modules of NEMS. For one thing, plant aggregation at the PADD level, as used in the PMM, may require a different approach be taken. For another, the investment decision process used may be different for different industries. It will be more realistic to use a methodology that resembles that used by the industry of interest. What is necessary is that the justifications for using different strategies be understood and be well documented. Where appropriate, these approaches should be anchored to the same global investment parameters used in other parts of NEMS. This said, within the PMM, careful consideration should be given to how to evaluate decisions involving unproven, alternative-fuels technologies, since these will be the most difficult to predict.

It should be kept in mind that the PMM by its very nature is not capable of making short-term forecasts. Therefore, the transition from the present to the mid-term should be analyzed exogenously and empirically represented in the model.

Based on the discussion above, the material presented in Section III, and the material presented on the current PPM investment methodology in the attachment, the following recommendations are made for future consideration by the EIA:

1. Mid-to-long term, petroleum refining-related, capital investment decisions based upon multiple metrics:
    a. Minimum return on investment should continue to be used as the primary decision metric, but may be constrained by maximum payback times, to account for limitations imposed by investment planning horizons, and/or maximum total annual investment, to reflect capital-budget limitations within the industry.
    b. The discount rate to be used for the estimation of capital charges may be based upon an appropriate hurdle rate above that of the cost-of-equity as currently calculated in the PMM. Different hurdle rates could be used for "must-do" projects related to changes in fuel regulations, short-term capacity expansion projects, and long-term strategic investments[2].
    c. A more accurate discounting procedure should probably be implemented for the capital-charge calculation to allow explicit consideration of the cost-of-equity and the cost-of-debt. The current methodology used to predict the cost-of-equity and debt however, appears sound; but should be reviewed and updated annually.
    d. In general, the current capital-cost estimation and financial analysis conducted within the PMM could be made more flexible by allowing all relevant parameters, such as hurdle rates, project economic and loan life, process contingency, etc. to be variable. This could be accomplished by storing these parameters in the PMM in the form of an array; thus, allowing the values to be unique for each process technology considered. Default values could be specified for standard refinery processes. A mechanism could then be developed to allow these parameters to be updated during the course of a forecast to reflect learning and other exogenous factors.
    e. Tax life should be based on standard accounting practices for the industry and should incorporate depreciation or other tax credits based on existing U.S. tax laws. The depreciation method used, straight-line, double-declining balance, etc., should be based on industry practices. Flexibility should be included to allow a variety of potential state and federal subsidies to be accurately modeled.

[2] Examples of long-term strategic investment within the refinery would be major capital-intensive expansions such as the addition of significant "bottom-of-the-barrel" processing including coking, hydrocracking, or gasification.

2. Short-term, petroleum refining-related, capital-investment decisions based upon an annual assessment by EIA of current industry expectations for the near future. This mechanism could be used to adjust hurdle rates, annual caps and the planning horizon in the early years of the forecast, in order to reflect outcomes predicted by exogenous analyses.

3. The decision to invest should be examined every year of the forecast and should be final. This decision can continue to be based upon an estimate of capital charges, and fixed and variable costs.

    a. The price spread between crude and finished products employed for the investment decision should however be based on historical levels, not future forecasts. This reflects the fiscal discipline within the industry and its conservative approach to investing. A running average (5-10 years) for price spreads could be tracked during the forecast period and used for this purpose.

    b. Appropriate construction time lags should be specified for all technologies, and capacity additions under construction should be accounted for when making future investment decisions.

    c. Regulatory-driven investments should be considered before they are needed. The construction lag plus some possible safety factor could be used to introduce these projects into the decision process.

    d. While a depreciation tax credit is currently considered as part of the investment decision, projected future income taxes are not. This is necessary since the PMM objective function is used for investment decision making and the objective function currently does not include corporate income taxes. It may be worthwhile for EIA to re-evaluate this approach to ensure that it is providing consistent decisions between alternatives.

4. Miscellaneous:

    a. Current practice within the PPM is to require the refinery to use all new capacity that is built in perpetuity. This practice was implemented to prevent the refinery from building units and not using them. In most cases, this is unlikely to occur if the decision process is being represented consistently within the model. This problem may result from including the capital charge and fixed operating costs for new capacity in the objective function after the investment decision is finalized. These are sunk costs after construction is complete, and should not remain in the objective function. However, it is conceivable that a unit might be built based on assumed product price spread projections and then not be operated when these margins do not materialize. This is a real-world risk and it is recommended that the practice of forced operation of new process capacity be discontinued.

    b. The PMM technology database is a separate component of the PMM module of NEMS. Even though a technology is represented in the database, does not mean that it should be included in all NEMS runs. In general, the PMM should not be used for picking technology winners and losers. In particular, multiple versions of the same process such as provided by different technology vendors) should normally not be included in a NEMS forecast. It is believed that this practice not only has the potential to result in over optimization, but also leads to infeasible scenarios by allowing non-existing pathways for refining crude into product. A good example of this is with regulatory-driven investments. It is unnecessary for the PMM to explore for the optimum solution. All that is necessary is to provide the PMM with one feasible option. Keep in mind that the PMM is based on aggregate refinery data and that most environmentally-driven investments are short-term investment propositions.

c. The PMM should not need more than about twenty different processes to predict refinery performance within the accuracy required for AEO projections. This said, within budget and time constraints, the EIA should strive to maintain an extensive, accurate and transparent database of process technologies that can be used both for the AEO and also for any special studies that may be requested in the future. It is difficult and time consuming to try to develop this type of data on the fly.

5. A "back-casting" exercise for the PMM is long over due, and is a necessity for the development of any new or improved investment procedure. If this effort is to be part of a larger one to develop a successor to NEMS, then it may be appropriate to develop the new PMM first as a stand alone program so that it can be easily modified and debugged during the early software development phase of the project.

6. EIA should also take a closer look at whether alternative fuels-related technologies should be considered in future reference cases for the AEO. As demonstrated repeatedly in the past, there is considerable danger in speculating on when, where and how much alternative fuels will penetrate the transportation fuels market (introduction of these technologies almost always requires a paradigm shift). A wiser approach may be to assume "business-as-usual" with some moderate level of learning over time for the reference case. The side cases run for the AEO provide an appropriate venue for considering "what-if" technology scenarios involving pre-commercial technologies currently under development. This approach more accurately represents how analyses are conducted in the private sector, where what-if analyses are used in the investment planning process. This approach facilitates identifying future energy problems and possible policy options and R&D solutions that might be pursued. The reference case for the AEO should be the "mirror" and the side cases the "telescope" for examining future energy policy.

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PMM Investment Decision Making

1. The U.S. refining industry is modeled in the PMM as five notional refineries representing the aggregation of individual refineries within five regions (PADDs) of the U.S. Individual refinery processes are modeled in each PADD. The initial capacities for each process are the sums of the capacities at all the refineries in the PADD at the beginning of the NEMS forecast. Processes in real refineries are integrated through the sharing of utilities such as electric power, fuel, steam, and cooling water. This integration is carried over to the PADD representations. In addition, many of the processes have multiple modes of operation. The Linear Program (LP) used in the PMM to simulate each PADD refinery for each year of the forecast optimizes the performance of the refinery operation by adjusting flowrates of the feed and intermediate refinery streams to each process to maximize profit, while meeting specified product demands and quality. This is a simplification since in the real world no one refinery possesses all the upgrading capabilities that are available throughout the PADD.

2. PADD level aggregation is carried over for alternative fuels technologies as well. These technologies are normally only represented at the plant level (*i.e.* component processes are not modeled). However, this does mean that all alternative plants of a given type are exact duplicates of each other (*i.e*. same capacity, same input, same output, etc.).

3. Due to aggregation at the PADD level, the addition of refinery unit capacity is indistinguishable whether this addition is a new stand-alone unit at the refinery or an incremental capacity increase obtained by de-bottlenecking an existing unit. It follows then that:

- For a given process technology, all process units have the same capacity
- Process capacity is added as increments of the nominal capacity represented in the model for a given technology
- Economies of scale are not considered, nor are differences in the cost of a unit revamp versus addition of a whole new unit
- Refinery shut downs, that is the losses of existing capacity in the PADD, are not considered.

4. The investment decision to add refinery unit capacity is made by the PMM in every third year of the forecast. Looking forward three years, the objective function for the PADD LP is optimized to select which process unit capacities should be increased to maximize refinery profitability. The objective function for this special optimization includes capital charges and fixed operating costs not included in a normal forecast year. Income taxes are not included in the objective; however, a depreciation tax credit is considered for new investments.

5. The incremental capacity obtained in Step 4 is added annually over the next three year period. The addition per year however is constrained so that it is not all added in any one year period. Once built this capacity must be operated in all future years of the forecast.