World Resources Institute

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# Western Oil & Gas Company: Strategic Financing for Energy Efficiency

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**Abstract**

Western Oil & Gas Company Corporation was considering a $2 million capital improvement project to upgrade motor systems at its Richmond, California oil refinery. In its original incarnation, Western engineers deemed the upgrade unwise due to operational limitations. Although it would increase energy efficiency and improve equipment reliability, the diversion of resources to implement the upgrade would risk disrupting 24-hour plant operations for a project that would not compete favorably with other potential capital expenditures.


**Summary: A complex system of actors and interests**

Western is a *Fortune 50* company focused on oil and gas production. In 1997, Western's net income exceeded $3 billion from revenues of over $40 billion. The company produced over 1.5 million barrels of oil and gas each day; 250,000 barrels were processed at the Richmond refinery. The Richmond refinery's output was almost entirely gasoline; a small remainder was made into other petroleum products.

In May 1997, Western was considering a $2 million capital improvement project to upgrade motor systems at its Richmond, California oil refinery. The motor system upgrades that Western was considering were not crucial from an operational standpoint. Their most obvious benefits to the refinery would be improved energy efficiency and process reliability. When compared to other capital projects at Western, these benefits were not viewed as a high strategic priority.


This case was prepared by Forrest Briscoe of the MIT Sloan School of Management and the JSI Research & Training Institute, with Hakeem Sanusi and Opoku Archampong of MIT Sloan. This case is intended to serve as the basis for class discussion rather than as an illustration of either effective or ineffective handling of an administrative situation. While the case is based on a real project, details have been changed. Data for the case were provided by Planergy Energy Services Company and ABB Energy Capital. The case benefited greatly from the advice and guidance of Donald Reed of WRI. Support was provided by the U.S. Environmental Protection Agency.

To investigate ways to balance the risks of the project with its true benefits, Western retained an energy services company (ESCo) named Energy Services and a specialized financing company named ABB Energy Capital. With the expertise of these partners, the Western plant manager was able to explore a set of financing options with differing implications for the project's costs, benefits, and risks.

**Background: Project specifications**

The motor system upgrade involved the installation of new equipment for the plant's "diesel hydro treater" (DHT), which takes feed from upstream processes and delivers throughput to downstream processes. While the DHT accounted for 10 percent of the refinery's total output, this figure understates the importance of its continued smooth functioning. The components of the refinery were highly interconnected and interdependent, and the failure of any one component posed an uncertain and potentially disastrous hazard to the operation of the rest of the plant. The refinery operated 24 hours a day, and continued operation was critical to profitability. Each lost day of production cost the refinery $1 million.

The project proposal called for several changes to the DHT motor system. Most important, electric variable speed drive (VSD) motors would be installed on the 2,250-hp primary feed pump and 700-hp product pump. They would replace constant speed motors, which were resulting in wasted energy, low hydraulic efficiency and excessive vibration.

The existing constant-speed motors had to be able to run at the maximum possible throughput that the pumps might have to handle during the day (1300 gallons of oil per minute). However, average throughput was much lower (800 gallons per minute). As a result, the pumps had to be throttled to 40 percent of their design speed during most periods of operation. This arrangement is analogous to running a car with the accelerator down and the brakes on at the same time. Obviously, electricity was wasted by running the pumps at a higher speed than necessary most of the time. Of equal importance, however, the vibration and strain on bearings and seals in the DHT created high maintenance costs and a greatly elevated risk of pump failure. The project would thus not only improve energy efficiency, but also improve process reliability.

In addition to moving to VSD motors, power recovery turbines would be installed to facilitate cold start-ups. The pumps would be "re-rated" to higher efficiency at lower flow, resulting in reduced electricity consumption. Related oil pumps and seal support systems would be improved. These would require some changes in operating procedures for the motors as well as the retraining of relevant operating personnel.

**Pre-project perspective: Energy efficiency at Western**

Richmond refinery engineers were aware of the attractive benefits that the DHT motor upgrade could offer long before 1997. Nonetheless, before the involvement of Energy Services and ABB Energy Capital, managers at Western were not even considering the project in their five-year planning process. Why? The benefits and costs were uncertain, the risks were significant, and the internal resources required to thoroughly evaluate the benefits, costs, and risks were lacking. In addition, the activity was not perceived as a strategic priority for Western.

The direct project benefits would include electricity bill savings and improved equipment reliability. The refinery engineers believed that the energy savings could be significant. The boost to equipment reliability would mean less downtime and lower maintenance costs. While these benefits would likely be realized, there were uncertainties about their magnitudes.

Project costs were similarly uncertain. The best guess of the two engineers most knowledgeable about the refinery's DHT was that the project would require around $2 million in up-front capital, all told. They believed the simple payback on this investment was somewhere between two and five years, but without further study they could not make a better estimate.

Potential risks from the project's implementation included the possibility of insufficient energy savings, as well as the more significant potential for disrupting operations during the transition. Any new equipment would require fine-tuning, and the extent of adjustments and their disruptive potential was hard to anticipate. As noted above, downtime was extremely costly. In addition, the installation of *electric* drives in a refinery environment that necessarily contains a flammable atmosphere increases the risk of fire hazard. (But the use of properly rated, spark-proof electrical components can mitigate this hazard.)

**Pre-project perspective: Implementation difficulties**

To better grasp the benefits, costs, and risks of the project, a feasibility study was needed. Refinery engineers were pressed for time with their existing responsibilities and could not undertake that assessment themselves. In part, this reflected the fact that Western's operations were staffed in a lean manner. Reorganizations in the 1980s had greatly reduced the number of engineering positions in the refinery.

Two important technical groups—chemical and electrical engineers—would have to be involved in the project and any feasibility study. Close collaboration would be essential, because the new motor drive was electric, and its installation posed considerable hazards.

But collaboration between these groups was historically difficult. Under the usual division of labor in the plant, the two groups rarely worked together. Worse yet, there was a tacit view (not unique to the Western organization) among the chemical engineers that their work was more difficult and, therefore, more important than that of the electrical engineers. This view tended to hinder collaboration between these groups.

To overcome this reluctance, some leadership and coordination would be required. But at the plant level, no one had clear responsibility for energy efficiency issues. At the corporate level, Western had an individual dedicated to energy efficiency issues, but her broader responsibilities had prevented her from any involvement in considering the motor system upgrade prior to Energy Services' involvement.

A final blow to the project's viability was its low strategic priority, both to the plant manager and to corporate headquarters. Electricity was not a large cost to the refinery. Refineries consume energy during the transformation of crude oil into useable petroleum products, and the Richmond refinery consumed about $25 million in energy each year. However, this amount is small when compared to the annual value of the refinery's products—over $5 billion.

Higher-ranked strategic issues at the plant included running round-the-clock production smoothly and safely. Redundant backup systems had to be maintained, ensuring a sufficient *supply* of energy for peak production periods, and maintenance had to be carefully conducted so as to minimize process disruptions. Safety was an ongoing concern, given the volatile materials involved.

At the corporate level, the finance department would have to approve the project if internal funds were to be used. Unfortunately, proposals responding to environmental regulation had recently crowded out most other proposals for spending internal cash. In 1995, Western committed almost *$1 billion* in future expenditures to upgrading refinery production in response to California clean air regulations. This money had funded the incorporation of MBTE into the refinery's gasoline product. (MBTE is a chemical additive in gasoline that results in more complete combustion in automobile engines.) Consequently, any non-critical capital expenditures had been put on hold for several years.

Given these factors, it would be difficult for the project to command serious attention at the corporate finance office. The corporate analysts were geographically removed from Richmond, and they would look at basic financial criteria—such as the simple payback period—to evaluate the upgrade project. From their perspective, the project had some merit, but hardly stood out from a long list of other proposals.

In sum, if Western had been considering the project on the basis of internal funding and in-house supervision, it would not have happened quickly. The motor upgrade might have looked better on paper had a feasibility study been performed, but no one at Western was going to do such a study, given the strain on internal resources and the low strategic priority of energy-related projects.

**The project context: Growing demand for electricity and changing regulations**

The Western project was investigated in the context of California's changing energy industry. The Richmond refinery purchased electricity from Pacific Gas & Electric (PG&E), the regional public utility. As a public utility, PG&E was obligated to provide for the growing demand for electricity in a multi-state region. PG&E provided funding that effectively subsidized projects such as the motor system upgrade because they helped to reduce the region's overall electricity demand. These subsidies were encouraged by the California state government and ultimately paid for through a "public goods" charge on consumers' electric bills.

PG&E had to be able to accommodate the region's peak load capacity (the maximum level of electricity use likely at any one time) in order to ensure service reliability. In doing so, however, it was required to pursue the cheapest possible options. This was PG&E's charge as a utility operated for the public good and governed in California by the state Public Utility Commission. The commission set electricity rates for residential, commercial, and industrial users and supported energy efficiency measures.

Given these constraints, the challenge for PG&E lay in managing growth. In planning its activities, the utility attempted to match capacity planning to future demand. This challenge became more difficult starting from the late 1970s, when energy prices climbed and destabilized and environmental awareness grew. Utilities like PG&E began looking at ways to avoid the construction of additional large power plants. They explored other options, included promoting conservation and load management, investing in renewable technologies, and constructing cogeneration facilities.

At the same time, the federal government began changing relevant regulations to reflect a growing public interest in energy conservation and environmental management. By the 1980s, the U.S. Environmental Protection Agency (EPA), through its mandate to improve the environmental quality of life for all Americans, had several programs targeting energy efficiency in industrial and commercial settings. These programs often provided information and technical assistance that encouraged companies to invest in energy efficiency. They also provided an added incentive, through public recognition or other means, for companies to undertake energy efficiency projects.

For example, ENERGY STAR Buildings℠, a voluntary partnership between U.S. organizations and EPA, was designed to promote energy efficiency in buildings. The program spanned manufacturing facilities, offices, retail stores, and government buildings. Organizations that joined the partnership followed a proven, cost-effective strategy to save money by reducing the total energy consumption of their buildings. The five-step strategy began with the implementation of Green Lights®, which involved installing readily available, proven lighting technologies that could reduce a building's lighting energy use by 50 to 70 percent. This was followed, in order, by a building "tune-up," other load reductions, fan system upgrades, and heating and cooling system upgrades. Participants that followed this approach were typically able to reduce their energy use by 30 percent while achieving an internal rate of return (IRR) of 20 percent or greater on their investment. EPA provided participants in ENERGY STAR Buildings with unbiased technical information, customized support services, public relations assistance, and access to a broad range of resources and tools.

As of February 2000, over three thousand organizations were participating in the ENERGY STAR Buildings℠ and Green Lights® Partnership, including more than a third of Fortune 500 firms. Cumulatively, these organizations had prevented 44.1 billion pounds of carbon dioxide ($CO_2$) from being released into the atmosphere as a result of their energy-efficiency upgrades. This was equal to removing the pollution from 1.6 million cars, or planting 2.2 million acres of trees annually. These organizations had cumulatively saved over $1.4 billion in energy bills.

**The energy efficiency industry: Demand side management of electricity**

PG&E and other utilities sponsored industrial energy conservation through "demand-side management" (DSM) programs that provided incentives to end-user companies to reduce energy use. The utility often paid for the averted electricity generation (called "negawatts") at rates comparable to the price it would have paid to buy new generating capacity (usually by building new plants).

While some energy efficiency projects were contracted directly between utilities and end-user industrial companies, another form of DSM contracting became common in the 1980s. In this arrangement, energy services companies (ESCos) would contract with utilities to provide a certain amount of negawatts at a set price in a set amount of time. The ESCo would then seek out opportunities to conduct DSM projects with a variety of end-user companies to meet the contract requirements. The ESCos developed strategic expertise in identifying and implementing particular types of energy efficiency projects.

Many ESCos specialized in industrial facility energy projects in energy-intensive sectors of the economy such as primary production and manufacturing. As the energy services industry matured, ESCos began providing other services such as rate negotiation expertise, power monitoring and information systems, and self-generation capabilities to end-user companies. While the DSM projects sponsored by utility companies were an important component of their business, ESCos also implemented many energy efficiency projects that paid for themselves *without* the subsidy paid by the utility for achieving negawatt savings.

The Western motor upgrade in Richmond was one of several projects sponsored by a single-utility DSM program. PG&E signed a six-year contract with Energy Services Corporation[1] in 1994 to provide 23 million kWh per year of negawatt savings. Energy Services was a nationwide ESCo founded in 1977 with expertise in a range of energy efficiency projects. Based in California, Energy Services had a long-standing relationship with PG&E that included several large DSM contracts.

Energy Services won the PG&E contract in a competitive bidding process that included proposals for various DSM activities as well as new generation proposals. From PG&E's perspective, the *way* bidders achieved the new capacity was secondary to the price. Either reducing demand or building new generation plants were viable options for achieving their goals. Energy Services' DSM proposal won the contract by underbidding proposals for new generation projects that had higher costs per kWh.

While ESCos developed operational expertise in energy efficiency projects, special financial arrangements were often required to make projects attractive to clients. A few firms recognized the opportunity to provide financing for energy efficiency projects that were relatively small (between $250,000 and $30 million), but for which the risks could be well characterized with the right in-house expertise. On this premise, these lenders built capabilities in assessing the technical and financial risk associated with industrial energy efficiency projects.

[1] By 1997, Planergy had been purchased by a larger organization called New Centuries Energy.

Energy Services had partnered on many energy projects with ABB Energy Capital, founded in 1990. Most of ABB Energy Capital's loans and leases were offered to an underserved segment of smaller energy efficiency projects. Because ABB Energy Capital was able to assess the risks of many energy efficiency projects quite well, they were often able to offer several different financial structures to customers. They were willing to structure loans and leases with up to ten-year paybacks because of their knowledge of the energy efficiency technologies being used. This flexibility contrasted with many internal capital allocation requirements that end-users may face and with general bank loans that would consider such financing riskier and require faster payback and higher interest rates.

**Project execution plan**

Energy Services had to find several energy efficiency projects in the region that would add up to the energy savings required by PG&E. With this in mind, Energy Services and Western met to discuss the proposed Richmond DHT motor upgrade in 1995. Energy Services offered a complete implementation package that included managing the feasibility study, audit, construction and ongoing monitoring (to verify the equipment's energy consumption).

Energy Services proposed to conduct the feasibility study, equipment purchase, and construction using its own experts working with engineers from Western's on-site motor vendors and the drive manufacturer. Western's own engineers would be freed from the details of evaluation. The vendor engineers would help ensure that projections were accurate and the installation would minimize interruption of Western's operations.

Using its own resources, Energy Services funded a six-month feasibility study to estimate the project specifications and costs. They convened meetings between Western's *corporate* energy efficiency manager and the *plant*-level engineers and managers, which without Energy Services' involvement might otherwise have never happened. They also collected information from Western's current vendors. The study found that construction would require about one year of work before the upgrade became operational. Once on-line, energy cost savings would ensue immediately. The new equipment would be highly durable, and the project's functional lifetime was expected to exceed 10 years.

The feasibility study estimated that direct project costs would total $2 million. This figure included the new motor equipment, construction costs, audit, Energy Services' fee, and the feasibility study. Energy savings resulting from the project were estimated to total around 31 million kWh per year beginning in the first year (at PG&E's price of 5 cents per kWh). These savings depended on refinery throughput, but Western planned to continue running the Richmond refinery at similar levels for the foreseeable future. The project would also reduce peak demand by an estimated 1 million kW per year for the life of the project.[2]

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[2] Electric demand is generally measured in kilowatt-hours (kWh), and is used to indicate cumulative electricity usage per period of time (such as per month or year). Peak or maximum load is indicated in kilowatts (kW), which measure electric power available at a moment in time.

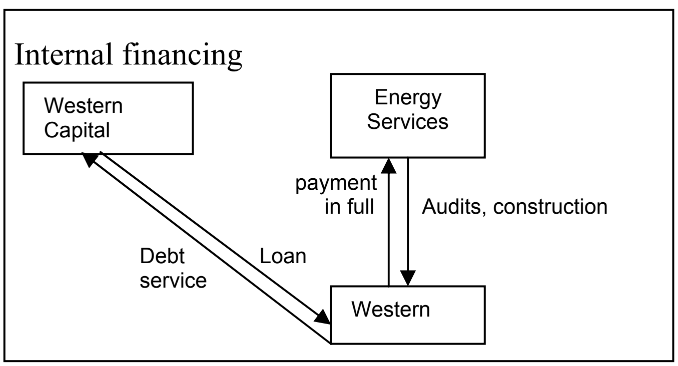
In addition to these direct costs, installation of the new motors would require one day of downtime, but the project was estimated to forestall five days of downtime over the ten-year operating life because of increased reliability. Also, each year of new equipment operation would require $75,000 worth of maintenance compared with the previous equipment, which required $100,000 in annual maintenance.

Going into discussions, Western knew that Energy Services was under contract with PG&E to receive DSM payments from PG&E worth 5 cents for each kWh of electric demand reduced at the Richmond refinery. Furthermore, Energy Services would receive 15 cents per kW of reduced *peak* capacity from PG&E, because this would help the utility to meet its total regional peak capacity requirements. Energy Services could potentially share a portion of these benefits from the DSM program with Western through their contracting arrangement.

**Project financing options**

Several project-financing structures might be appropriate. The company could simply fund the project out of its internal capital budget. Alternatively, they could elect lease financing or "performance-based" financing, both offered through Energy Services by ABB Energy Capital.

**Internal financing** ties up capital resources for the purchase of equipment and funding of construction and other services. Using internal financing, Western believed it would be able to depreciate the equipment according to the five-year asset class schedule.[3]

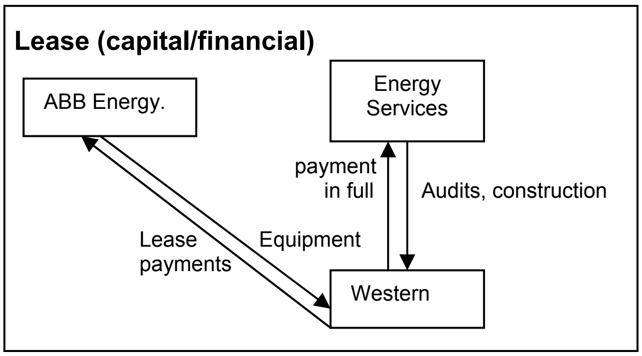



For internal financing, the Western project would have to pass an internal approval process. The capital budgeting process for internal funds was normally a straightforward question of return on investment in the project as compared to other projects under consideration. However, in 1997 it was complicated by the recent massive MBTE upgrade expenditures. Operating flexibility was already constrained by this earlier unanticipated outlay. As a result, the balance sheet impact of the motor system upgrade would likely be viewed negatively by corporate finance. Given this context, internal financing would require a rapid payback in order to even be considered.

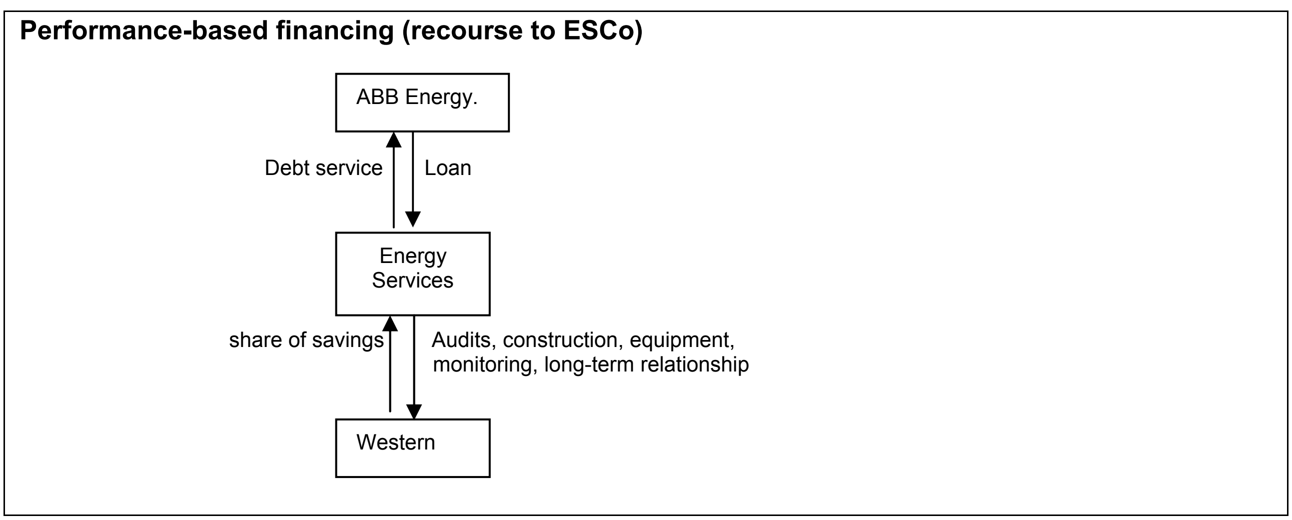
[3] The 5-year schedule allows 20 percent of the total cost to be depreciated in the first year following acquisition, and 32 percent, 19.2 percent, 11.52 percent, 11.52 percent, and 5.76 percent for the following years.

**Lease financing** involves a lease contract between the lender and the end-user to pay for the equipment and installation. The ESCo contracts directly with the end-user for construction, equipment, and other services. Thus, the ESCo is paid in full and the end-user bears the lease responsibility.

Leases require a stream of regular payments in exchange for the use of equipment, after which point the equipment reverts to the lessor. Factors which can influence the lease structure include the nature of the equipment and its intended use, the economic life of the equipment, the tax rates to which the lessee and lessor are subject, any maintenance provided under the lease arrangement, and any transaction costs necessary for the lease, such as due diligence audits.




In **performance-based financing**, also known as "shared savings" or "project" financing, the end-user gives up a percent of the project energy savings in exchange for obtaining the equipment and having it installed and managed. Under performance-based financing, the lender offers a loan directly to the ESCo rather than to the end-user. In turn, the ESCo contracts with the end-user to implement the project in return for a percentage of the energy bill savings.




The main advantage of performance-based financing for the end-user is that recourse on the loan is to the ESCo. From the end-user's perspective, the servicing of the loan is paid out of the project's energy cost savings.

Usually, performance-based financing calls for a percent of savings to be paid by the end-user to the ESCo. In this case, if energy savings are smaller than expected, the end-user simply receives less savings than expected. The ESCo must continue repaying the project loan regardless. Thus the ESCo bears the performance risk and also has an upside incentive to ensure optimal project performance. An additional advantage is that performance-based financing loans are likely to be considered off-balance-sheet for the end-user.

With the performance-based financing option, Energy Services offered to conduct maintenance activities on the equipment themselves, for the life of the project, using their own personnel and funds. Because they would share in the financial savings from efficient equipment operation, they would have a financial interest in maintaining the equipment for the life of the project.

Presented with these three financing options, the Richmond plant manager had to decide if the expertise of Energy Services and ABB, and the financing options they offered, added up in a way that justified implementing the project.

## Assignments

### Assignment 1. Discussion: Why don't all positive-NPV projects happen?

Why did Western not implement this project on its own, despite the reasonable numbers? Why did the scenario change?

### Assignment 2. Financial analysis

You are the Richmond plant's finance manager. Consider Western's choices for financing the motor system upgrades. Project benefits are estimated to last 10 years.

**Part A:** First, Western should evaluate the investment decision (without considering the financing). Compute the **project benefit** (at time t=0) using simple methods. Assume that Western's WACC is 11 percent, while Energy Services' is 12 percent. Also, Western is subject to a 40 percent marginal tax rate for U.S. operations.

Determine the simple payback and the Internal Rate of Return (IRR). Then calculate the Net Present Value (NPV) assuming that the entire investment depreciates according to the 5-year asset class schedule. This NPV will become the basis for evaluating alternative financing options to the use of internal capital.

**Part B:** After deciding to invest in the project, Western could have opted to finance it through a lease or performance-based arrangement instead of internally. First, evaluate the **lease financing** offered by ABB, as compared with internal financing. Assume that ABB offered a lease with seven equal annual payments that total to the value of equipment and installation ($2 million), and that the leasing market is competitive. ABB is subject to a 40 percent marginal tax rate. Does this qualify as an operating or capital lease? Considering the nature of the project, could it qualify as either with the right payment scheme? Compute the NPV of the lease option for comparison.

**Part C:** Now evaluate the **performance-based financing** option offered by Energy Services. Assume that Energy Services offered to fund the project for payment equal to 50 percent of the energy cost savings for five annual payments. Compute the NPV of this option for comparison.

**Part D:** Rank the financing options based on this analysis and explain why the analysis produced these results.

**Assignment 3. Discussion: Qualitative Analysis of Financing Options**

What financing option do organizational and strategic considerations favor? Consider the capital approval process and the company's context at the time of the project.

**Assignment 4. Negotiating the performance-based financing structure**

Now assume that you have selected a performance-based financing structure for the project. As the chief financial manager for the refinery, you are going to be negotiating with Energy Services and ABB over the details.

**Part A:** Because you know that Energy Services is receiving DSM payments from PG&E, you reason that you should investigate Energy Services' likely cashflow with the energy-savings payments and DSM payments. Compute the NPV, assuming that PG&E will make DSM payments for six years. Do not include any financing costs for Energy Services, or project fees or overhead. Include the full project cost up front, as you did with Western's initial investment decision.

Energy Services must maintain the new equipment for the life of the project (assume the same cost that Western would have incurred). They must also operate monitoring equipment costing $40,000 per year for the life of the project, to verify for Western and PG&E that the required energy savings are being achieved. Assume the project is subject to a 40 percent tax rate, and has a 12 percent WACC.

Calculate the simple payback and NPV.

**Part B:** Energy Services has offered you a performance-financing contract with a provision for payments of 50 percent of energy savings. However, as a shrewd plant manager, and with your analysis of Energy Services' cashflows in hand, you believe there may be room to bargain. What percent of the electricity cost savings from the project might you propose? What leverage points do each of the parties have? What practical matters might factor in?

**Part C:** Consider offering to pay a set dollar amount per avoided kW of energy, rather than a set percent of total savings? What difference would this make?

**Part D:** During negotiations, Energy Services argues that Western should consider that Energy Services spent $500,000 of their own funds for the initial project feasibility study. How should you respond? (Be brief.)

**Assignment 5: Additional financial analyses**

**Part A:** Using spreadsheets, explore the implications for structuring the financing (or undertaking the project at all) when the price of electricity varies (for the life of the project).

**Part B:** Explore the implications for structuring the financing (or undertaking the project at all) when the project's WACC varies (for the life of the project).

**Part C:** Consider the residual value of the project. What NPV does the estimated four-year project life following the end of any payments hold? How does this value change when the WACC varies?

**Appendix 1**

## Various finance options available for energy projects

By Fred Wainwright, *Energy Capital Partners*
*Energy User News - March, 1997*

**BOSTON** - Although energy-efficiency projects require much technical and engineering expertise and ultimately save valuable natural resources, the decision-making process from the customer's perspective boils down to one factor: money. Unfortunately, many energy services companies (escos) lose sight of this fact when they develop projects for customers. Far too many projects receive hundreds of hours of technical review only to be followed by a 30-minute meeting with the chief financial officer of the customer.

"Here's your payback. Would you like to pay cash or lease?" often is the boilerplate question.

Lenders, on the other hand, are guilty of becoming so standardized in their product offerings that if customers don't fit a specific formula of financial qualifications, the project is doomed. It behooves escos and lenders alike to become experts in providing customized options. It is crucial to the success of a project that the customer be educated early in the process with regard to the full range of financing options. In doing so, the facility manager, CFO, esco engineer, and lender can work together as a team.

Performance contracting can be defined as performance-based energy-efficiency projects. Sometimes an esco will guarantee a minimum amount of savings for the customer, while other times the esco and customer simply share in the savings generated by the project. Following are various financing options available today for customers.

### Bonds

City and state governments can issue bonds to raise money for improvement projects. Typically, these are general obligation bonds backed by the full faith and credit of the borrowing entity. The most well-known companies that provide credit ratings are Standard and Poor's and Moody's. These credit agencies have tremendous power because they determine, in essence, the interest rate at which funds will be borrowed. Even a 0.1 percent difference in rate can represent many thousands of dollars in additional interest expenses over a long period of time.

These agencies change their ratings as much as several times a year if significant financial news develops regarding the individual municipality or state. Bond issuances typically carry hefty fees for legal, underwriting, and bond selling costs. However, bonds may be a sensible alternative for large energy projects that are identified well in advance of the bond issuance. There is no such thing as a quick bond offering, so if an energy project is developed in-between bond offerings (usually every two years), it will be placed on hold.

### Leases

Equipment leasing has enjoyed a tremendous surge in popularity in a wide variety of industries. Leasing offers many benefits over outright ownership of equipment. It provides the advantages of reasonable interest rates - based on the credit quality of the customer - and flexibility with the timing of funding the project.

For certain borrowers, municipalities, and other tax-exempt entities, interest rates can be quite advantageous, falling in the range of 5-7 percent for up to 10 years. These leases are known as municipal, or tax-exempt, leases. They are full faith and credit obligations by the customers. That is, as long as the tax-exempt entities have allocated the funds in their annual budgets, they must make the payments on the leases regardless of the performance of the newly installed equipment.

## Appendix 1

There are many categories of leases, but the primary distinction is in the way that a customer recognizes a lease on his financial statements. Capital leases are structured as debt on the customer's balance sheet. In other words, as far as the accountants are concerned, the customer has bought the equipment and the lease is a form of a purchase financing. A majority of energy equipment leases are capital leases. Technically, a capital lease is one that meets any of the following criteria:

* The lease transfers ownership of the property to the lessee (customer) by the end of the lease term;
* The lease contains a bargain purchase option that is less than fair market value;
* The lease term is equal to 75 percent or more of the estimated economic life of the leased equipment;

or

* The present value of the minimum lease payments equals or exceeds 90 percent of the fair market value of the leased property.

Conversely, operating leases - often known as off-balance sheet leases - technically are not considered a debt and therefore do not appear in the customer's financial statements.

It is advisable for the customer to check with a certified public accountant prior to entering into an operating lease agreement. There have been cases in which independent auditors have determined that supposed operating leases were technically capital leases, thereby forcing customers to reorganize their financial statements for the previous few years. This would alarm chief financial and chief executive officers, and therefore would reduce or eliminate the chance of an esco receiving future business from those companies.

As with municipal leases, both capital and operating leases are full faith and credit obligations of the customers; lease payments must be made regardless of the performance of the equipment or of any guarantees of energy savings made by escos. Here, typical lease rates are 7-12 percent, depending on U.S. interest rates.

### Project Financing

Project financing, also known as shared savings or performance contracting, is an innovative financing option in which the lender makes a loan directly to the esco rather than to the customer. In turn, the esco contracts with the customer to provide energy conservation measures by means of an energy services agreement. This agreement specifies the percentage of the project's generated savings, which will be paid by the customer to the esco. Usually in the first few years of the agreement, the esco will receive a higher percentage of the savings (75-100 percent) in order to be able to make the loan payments and a return on its investment.

Since the loan is made directly to the esco, it has a very high likelihood of being considered off-balance sheet by the customer's accountants. The customer also receives the benefits of having new equipment installed without any initial cash outlay and paying for the project over time, but only based on the actual performance of the equipment. Project financing creates a win-win situation for customer, esco, and lender; all three parties will be very motivated to ensure that the project produces savings. The customer should be comforted by the fact that a lender is financing the esco, because if the esco ever fails in its obligations under the energy services agreement, the lender will have the right to replace the esco in order to ensure that the project continues to generate savings.

The esco uses the borrowed funds to recoup project development expenses and install the equipment. Repayment to the lender is made by the esco from the savings payments made by the customer. One variation of project finance includes a corporate shell or single-purpose entity created exclusively to hold the assets and the liability of the project financing. In certain cases, this allows the esco to limit its liability to the lender should the customer go out of business or the project perform under expectations.

**Appendix 1**

The lender will make a thorough analysis of the projected savings in order to determine the likelihood that actual savings will be sufficient to cover the loan payments. The lender also will want to evaluate the esco in terms of project experience, as well as evaluate the energy savings agreement as a document that can withstand the test of time. The agreement should set forth procedures in case of any material changes that could possibly occur in the future. Termination clauses or changes in customer operating hours are just some of the conditions that should be addressed. In addition to reviewing projected revenues and expenses pertaining to the project, the lender will want to review two or more years of audited financial statements from the esco and the customer

Since the lender is primarily relying upon the strength of the project, the credit strength of the customer is not the only factor in developing an interest rate for the loan to the esco. Usually the rates are 9-14 percent, but these figures will vary. If a default occurs between the esco and the customer and the customer has the right to reduce or cease its payment obligation, it is the lender who is most at risk of suffering a loss.

The esco should involve the customer's financial executives early in the process of developing a project, since they will be making the ultimate capital investment decision. The lender should bring value to the transaction by offering a variety of financing choices and a commitment to work as part of the team. All parties involved should aim to achieve a mutually beneficial project structure that will ultimately exceed the customer's expectations.

Judging from the requests for proposals recently issued by the U.S. Departments of Energy and Defense for performance contracts that exceed $ 1 billion in value, federal projects clearly represent a major opportunity for escos. As the federal government consumes nearly $ 8 billion per year in utility bills, the goal by 2005 is to produce a 30 percent reduction in these bills compared to 1985 levels, which represents approximately $ 5 billion in energy efficiency projects.

It is crucial that federal contracting officers, escos, and financiers understand the importance of working together as a team. Together they can build successful, long-term projects that will save tremendous amounts of energy, natural resources, and dollars.

Fred Wainwright is vice-president of marketing for Energy Capital Partners, a company that provides financing for energy-efficiency projects.