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The Operating Industries, Inc. (OII) Landfill is a closed landfill near downtown Los Angeles, California. A new microturbine-based power plant installed at the site allows OII to substantially reduce its power costs while still meeting the strict emission requirements for gas emitted from the site.

Microturbines show their flare for landfill

The Operating Industries, Inc. (OII) Landfill is a closed landfill located 12 miles east of downtown Los Angeles, California. It currently produces landfill gas which has been treated with a thermal oxidizer capable of a destruction and removal efficiency (DRE) of 99.99 per cent. Any attempt to utilize the landfill gas for energy generation in the past was hampered by the requirement for 99.99 per cent DRE.

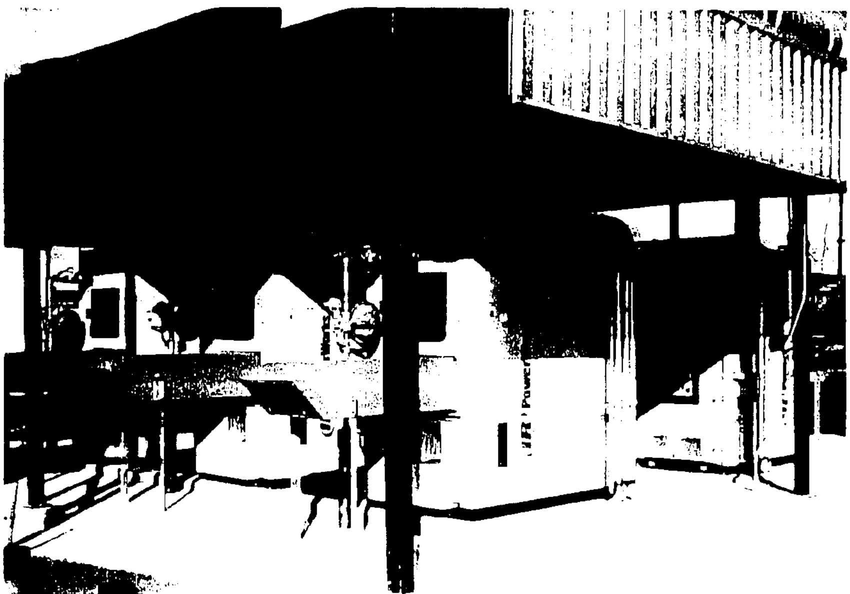
In July 2001, the California Public Utility Commission (CaPUC) allowed the local utility serving OII, the Southern California Edison Company (SCE), to raise its retail rate from 10¢/kWh to 14¢/kWh. As a result of this increase, OII's annual power cost increased to $440 000. SCS Energy (SCS) proposed that a power generation feasibility study be undertaken, and New Cure, Inc. (NCI), the contractor for the Work Defendants, authorized SCS to undertake a feasibility study.

At the outset, the following boundaries were set on the study:

- Limit the project's size to the on-site load: SCE was not buying power, and even if SCE was buying power, a "retail deferral" type project would have a lower capital cost and a higher return on investment;
- Fuel the project exclusively on landfill gas; and
- Limit the generation technology to be considered to microturbines. Microturbines were considered to be the favoured technology because: the landfill gas at OII has a low methane content; low NO_x emissions were a high priority with regulators; and a relatively small plant capacity was required.

A review of the power bills at OII showed that four major loads accounted for more than 95 per cent of the landfill's power consumption:

- The landfill gas treatment system (LFGTS) itself;
- The leachate treatment plant (LTP);
- The office building at the landfill (known as the eight-wide); and


The OII microturbine power plant

- The booster blower.

Table 1 summarizes the power loads and costs at each of these four locations, each of which was served by a separate SCE meter. The LFGTS and LTP are adjacent to each other; however, the next nearest power load is the eight-wide, about 670 m away across the eight-lane Pomona Freeway. The final load, the booster blower, is a further 580 m away.

SCS's study recommended that the loads at the LTP and LFGTS be combined and be served by a 350 kW facility, that the eight-wide be served by a 70 kW facility, and that the booster blower be served by a 30 kW facility. The feasibility study indicated that all these projects were financially feasible. NCI submitted the SCS study to USEPA for funding approval in September of 2001.

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Project refinement

After reviewing the proposed project, USEPA decided that, for consistency, a DRE of 99.99 per cent would be required for any landfill gas burned in the microturbines (i.e., the 99.99 per cent DRE requirement would apply whether the landfill gas was flared or was beneficially used). It was expected that microturbines could achieve at least a 99.5 per cent DRE, but this was short of USEPA's requirement.

SCS proposed a solution in which the exhaust from the microturbines could be directed into the LFGTS thereby meeting the DRE of 99.99 per cent. The microturbines would consume only about five per cent of the total landfill gas burned in the LFGTS, and the introduction of the microturbine exhaust would not disturb LFGTS operation. USEPA approved this solution; however, the recommendation to install 70 kW and 30 kW microturbines on the other side of the Pomona freeway had to be abandoned because of the requirement to route the exhaust gas to the LFGTS.

As mentioned, the typical methane percentage at the LFGTS is low. It ranges from about 25 per cent to 28 per cent, but microturbines can successfully operate only at methane contents as low as 30 per cent.

The methane content in the landfill gas at OII is somewhat variable due to the presence and operation of the perimeter extraction well system. The basis for microturbine design was 35 per cent methane content; however, in actual operation the methane content has varied from 29 per cent to 47 per cent.

Plant description

The plant configuration comprises:

- A dedicated landfill gas transmission line;
- Piping interconnection with the flare station and condensate collection system;
- A 30 kW, 425m³/h landfill gas blower which raises gas pressure from -150 mmHg to 690 mbar;
- A refrigeration system which chilled the compressed landfill gas to 4.5°C, coupled with a heat exchanger to reheat the chilled gas to -7°C above the dew point;
- Six 70 kW Ingersoll-Rand (I-R) PowerWorks microturbines;
- A 9m x 9m metal deck cover over the turbines;
- Exhaust ducting;
- Switchgear and utility equipment;
- Continuous fuel gas quality analyzer (methane and oxygen);
- Motor control centre for the motors on the compressor skid; and
- Plant control computer with touch screen interface and off-site wireless access.

The landfill gas extraction system at OII includes a large in-soil, perimeter well extraction system that dilutes the gas delivered to the flare station to less than 30 per cent methane. The dedicated collection header taps into the existing collection system where the gas quality is typically 35 per cent to 40 per cent.

The I-R microturbines require a pressure of 5.5 atm[g]. They incorporate a factory-supplied on-board compressor, but the compressor could not be factory-upsized to raise the required quantity of landfill gas from -150 mmHg to 5.5 atm[g]. To overcome this problem, a positive displacement blower was used to "pre-pressurize" the landfill gas to 690 mbar. A chiller and heat exchanger were provided for moisture removal.

The pre-treatment equipment, including all non-utility electrical and control equipment, was designed and constructed on one skid. This allowed for assembly and initial testing of the skid to be completed off-site.

In order to meet the 99.99 per cent DRE requirement for flared landfill gas, the LFGTS is equipped with combustion air fans to enhance the fuel mixing and combustion. It was possible to meet the 99.99 per cent DRE requirement with microturbine exhaust gas routed into the combustion air blowers because:

- The oxygen content in the exhaust of the microturbines is very high, and is high enough to not impact mixing and combustion in the flare;
- The air temperature from the microturbine exhaust would be acceptable to the combustion air fans (after pre-mixing and dilution with ambient temperature combustion air); and
- Control of the microturbines would be interlocked with the operation of the LFGTS in order to avoid back-flowing the microturbine exhaust out the combustion air inlets (which could occur if the LFGTS was offline and the microturbines were on).

"The typical methane percentage at the LFGTS is low. It ranges from about 25 per cent to 28 per cent but microturbines can successfully operate only at methane contents as low as 30 per cent"

Six 70 kW PowerWorks microturbines are installed at the site

SCE interconnection issues

Virtually every distributed generation project, which has the ability to access a utility electric power distribution system, operates in parallel with the utility. The power generation equipment and the on-site power loads are continuously connected to the utility through a closed main breaker. Standby and supplemental power from the utility is instantaneously fed by the utility if there is a problem with the power generation equipment and/or if on-site power demand spikes above power generation capacity. If permitted by the utility, excess power produced by the power generation equipment can flow into the utility's distribution system.

Three options are available when excess power generation capacity is available:

1) *Match power production to on-site load* – Under this scenario, power is not exported to the utility and is commonly called the "no export" option. If an applicant accepts this option, the utility generally requires strict adherence to this condition. The utility requires the installation of a reverse power relay which detects when any export of power occurs and which immediately calls upon the main breaker to the utility to open. When the main breaker opens, it is not possible to close it without shutdown and restart of the power generation facilities. Obviously, this undermines the advantages of parallel operation. Activation of the reverse power relay would generally occur when the power generation equipment cannot reduce its rate of power production fast enough to follow dips in on-site power demand. A solution to this problem is to operate the power generation facility at an output below the actual on-site load, allowing some utility power to be backfed at all times, despite the availability of

Table 1. OII annual power loads and costs

	Peak	Average	¢/kW	Annual
Cost				
LFGTS	232 kW	205 kW	14.5	$260 000
LTP	130 kW	63 kW	14.6	$81 000
Eight-Wide	86 kW	43 kW	14.6	$56 000
Booster Blower	40 kW	33 kW	14.4	$42 000
Total	**448 kW**	**344 kW**		**$439 000**

adequate power generation capacity. The obvious disadvantage to this arrangement is that power is being unnecessarily purchased;

2) *Inadvertent, uncompensated export of power* – Under this scenario, a negotiated maximum amount of power can be exported to the utility, but the utility does not pay for the power. The problem of matching power generation to on-site load can be eliminated by always generating a little more power than is needed. If the distributed generation facility is fired on conventional fuel, the fuel is an expense, and an unnecessary cost is incurred to generate the "unneeded" excess power. At OII, the fuel is available at no cost and fuel cost is not an issue. A second disadvantage to the inadvertent export scenario is, at least in California, that the utility review of the interconnection application takes longer, is more costly, and can result in more extensive and costly utility-installed equipment on the utility side of the meter. The applicant is required to pay these costs in full at the time of installation;

3) *Export of power with sale of power* – California utilities are currently required to buy power, at their avoided cost, only for projects less than 100 kW in size. At the present time, there is virtually no market for sale of electric power in California.

It was clear that scenario 2 was the preferred option, provided that SCE's requirements did not become unacceptably onerous in terms of lost time and money. Several meetings involving almost a dozen SCE representatives (technical, financial and regulatory) ultimately led to SCE's acceptance of scenario 2 with an export limitation of 150 kW.

At the conclusion of this process, NCI marveled at how difficult it was to give free power to a utility in a state which less than a year before was facing power blackouts and soaring wholesale prices.

It took 86 days from the date the interconnection application was filed through the day it was approved. In hindsight, the rather complicated application was processed in a reasonable amount of time. SCE ultimately charged NCI $105 000 for up-grades on the utility side of the meter. The upgraded facilities included a new main transformer, a ground bank and wiring modifications.

Selection of the inadvertent export interconnection option has proven to be a wise choice. The power demand at the site has significant swings. Notably, there is a diurnal variation in power plant output. The capacity of a combustion turbine is affected by ambient air temperature, because air temperature affects the density of the combustion air. Power output is greater when the ambient air is cooler. The electric power demand is higher at OII at night, since the air blowers associated with the LTP's batch treatment process are run at night, in a conscious decision to match maximum load with maximum power output.

"Microturbine maintenance is expected to represent about 70 per cent of the plant's overall operation/maintenance cost"

Financial considerations

NCI minimized its financial risk through risk sharing contracts with SCS and I-R. NCI signed a turnkey construction contract with SCS, which called upon SCS to provide design, permitting, equipment installation and start-up on a time-and-materials basis for a guaranteed maximum price of $1 080 000. The turnkey contract placed construction cost risk on SCS, prior to the plant being designed.

NCI signed a five-year, fixed price microturbine maintenance contract with I-R. Under this contract, I-R provides all scheduled and unscheduled maintenance required by the microturbines for $8000 per microturbine per year (about 1.5¢/kWh). Microturbine maintenance is expected to represent about 70 per cent of the plant's overall operation/maintenance cost. As a result, NCI has a fixed operation/maintenance cost for the plant at a guaranteed price for a five-year period. More importantly, the cost risk from the plant component that had what was believed to represent the greatest risk, was virtually eliminated by the I-R contract.

SCS was able to bring additional financial benefits to the project in the form of grants. Prior to the initiation of construction, SCS secured a $105 000 grant from the California Energy Commission (CEC). The grant was paid to NCI through SCS at project completion. The grant represented $250/kW and was offered under CEC's innovative peak load reduction programme.

As construction of the plant was nearing completion, SCS identified another opportunity for a grant. The California Public Utility Commission (CAPUC) directed investor-owned utilities in California to modify the then existing eligibility criteria for the Self-Generation Incentive Programme. The programme was extended from what was a cogeneration-based eligibility criterion to add non-cogeneration projects which were fired on at least 75 per cent renewable fuel. SCS prepared an application for funding under the Self-Generation Incentive Programme and submitted it to SCE within days of the CAPUC action. SCE's Programme Administrator first learned of the change in criteria when he received the application from NCI.

Rapid application for the grant was paramount because grants are awarded on a first-come, first-qualify basis with a limited pool of funds being available. NCI's application was the first filed under the programme's new criteria and was the first project funded. The grant was in the amount of $450 000 and SCE directly paid the grant to NCI.

After full consideration of construction costs and ongoing operation/maintenance costs, the projected payback on the original investment is expected to be about two years.

Initial operation

The power plant first produced electric power in late August 2002, about six months after NCI's execution of the turnkey contract with SCS.

By October 2002, most start-up and debugging activities were complete. During October 2002 through January 2003, the plant was online 86 per cent of the available hours. By the end of January 2003 the plant was online 95 per cent of the available hours. The microturbines have demonstrated the ability to operate at methane contents as low as 29 percent. Savings in avoided electrical costs have recently approached $30 000 per month.

Figure 3. Power output is greater when the ambient air is cooler