Appendix IV

Average Equipment Component Schedules for Natural Gas Processing Plants

Table IV. Summary of average equipment component schedules for processes at natural gas processing plants

Process Unit	C	CCV	CS	CV	OEL	OM	PRV	PS	REG	V	Grand Total
Amine	147	-	-	1	5	-	1	-	-	45	199
Boiler	110	-	-	9	8	-	-	-	5	28	160
Comp	35722	32	278	186	680	10	83	5	216	2899	40111
Comp (Turbine)	426	-	6	15	-	-	3	-	3	102	555
Comp. Elec	826	1	-	3	-	1	1	-	-	37	869
Cooler	5387	-	2	19	20	-	-	-	-	262	5690
Dehy	1628	-	-	15	39	3	9	-	20	289	2003
Demethanizer	4141	-	-	41	66	1	9	20	-	681	4959
Inlet Separation	5294	-	-	57	86	14	17	-	18	1140	6626
Mole Sieve	407	-	1	26	2	-	4	-	-	112	552
NRU	407	-	-	27	9	-	-	-	1	102	546
Sales	1116	-	-	23	4	13	-	3	17	424	1600
Stabilizer	1281	-	0	5	5	1	1	2	-	107	1402
Well	897	-	-	8	14	3	6	-	19	156	1103
Grand Total	57789	33	287	435	938	46	134	30	299	6384	

Appendix V

Financial Considerations and Assumptions

Financial Discount Rate

The discount rate and opportunity cost of equity in the gas industry is arbitrarily taken to be six percent. Most oil and gas ventures are expected to yield better than bank interest to compensate for the added risk involved.

Net Present Value (NPV)

The net present value of each target control option is the present value of benefits minus the present value of costs. The analysis period in each case is the expected life of the control measure (e.g., the average repair life or mean time between leak occurrences).

Payout Period

The payout period of each target control option is the number of periods (years) required to payout the net present value of the repair costs based on annual payments equal to the value of the net benefit of repairs.

Equalized Annual Value

The equalized annual value of each control option is the total value of the option (after capital and operating costs) expressed as an equivalent series of equal annual payments spread over the life of the project. Negative values indicate a net cost.

Value of GHG Reduction

The value of a GHG emission reduction option is simply calculated as the equalized annual value divided by the average annual CO_2-equivalent reduction.

Appendix VI

Basic Component Repair Costs and Mean Repair Life

Table VI-1. Summary of repair costs and mean life of repair for equipment components in natural gas and non-methane hydrocarbon service.

Source	Category	Size (inches)	Basic Repair Cost ($/source)	Mean Repair Life (years)
Compressor Seals	Reciprocating	-	2 000	1
	Centrifugal	-	2 000	1
Compressor Valve Covers	All	-	200	1
Compressor Variable Volume Pocket Stem	All	-	400	1
Compressor Cylinder End	All	-	400	1
Flanges	All	0.5 - 0.75	25	2
		1 - 2.5	50	
		3 - 4	75	
		6 - 8	100	
		10 - 14	150	
		16 - 20	200	
		24 - 30	300	
		32	400	
Lube Oil Vent	-	-	4 000	1
Open-Ended Lines	All	0.5 - 0.75	60	2
		1 - 1.5	75	
		2	100	
		3	120	
		4	190	
		6	245	
		8	350	
		10	500	
		12	595	
		14	780	
		16	890	
		20	1 115	
		24	1 340	
		30	1 670	
Orifice Meters	All	-	150	1
Other Flowmeters	All	-	150	5
Pressure Relief Valves	Threaded	0.5 - 0.75	79	2
		1 – 2	84	
		2.5	95	
		3	107	
		4	135	
		6	203	
		8	270	
		10	338	
		12	405	

Continued ...

Table VI-1. Summary of repair costs and mean life of repair for equipment components in natural gas and non-methane hydrocarbon service (continued).

Source	Category	Size (inches)	Basic Repair Cost ($/source)	Mean Repair Life (years)
Pressure Relief Valves	Flanged	1	124	2
		1.5	130	
		2	135	
		2.5	146	
		3	180	
		4	214	
		6	253	
		8	290	
		10	363	
		12	435	
		16	580	
		20	725	
Pump Seal	All	-	500	1
Regulators	All	-	175	5
Threaded Connections	Pipe Thread	0.125 - 0.75	10	2
		1 - 2.5	15	
		3 - 4	25	
		6 - 8	50	
		10 - 14	100	
		16 - 20	150	
		24 - 30	200	
		32	300	
	Union	0.5 - 0.75	50	2
		1 - 2.5	100	
		3 - 6	150	
Tubing Connections	All	0.5 - 0.75	15	4
		1 - 2.5	25	
Valves	Ball	0.5 - 0.75	60	4
		1 - 1.5	75	
		2	100	
		3	120	
		4	190	
		6	245	
		8	350	
		10	500	
		12	595	
		14	780	
		16	891	
		20	1 114	

Continued ...

Table VI-1. Summary of repair costs and mean life of repair for equipment components in natural gas and non-methane hydrocarbon service (continued).

Source	Category	Size (inches)	Basic Repair Cost ($/source)	Mean Repair Life (years)
Valves	Butterfly	0.5 - 0.75	120	2
		1 - 1.5	150	
		2	200	
		3	240	
		4	380	
		6	490	
		8	700	
		10	1 000	
		12	1 190	
		14	1 560	
		16	1 783	
		20	2 229	
	Control (all types)	0.5 - 2	130	2
		3	141	
		4	177	
		6	282	
		8	353	
		10	459	
		12	560	
		14	653	
		16	747	
		20	933	
		24	1120	
	Gate	0.5 - 0.75	60	4
		1 - 1.5	75	
		2	100	
		3	120	
		4	190	
		6	245	
		8	350	
		10	500	
		12	595	
		14	780	
		16	920	
		20	1 000	

Continued ...

Table VI-1. Summary of repair costs and mean life of repair for equipment components in natural gas and non-methane hydrocarbon service (concluded).

Source	Category	Size (inches)	Basic Repair Cost ($/source)	Mean Repair Life (years)
Valves	Globe	1 - 1.5	75	4
		2	100	
		3	120	
		4	190	
		6	245	
		8	350	
		10	500	
		12	600	
		16	800	
		20	1 000	
		24	1 200	
	Governor	All	200	4
	Injector (fuel gas)	All	200	4
	Needle	0.125 - 0.75	60	4
		1 - 1.5	75	
		2	100	
		2.5	125	
		3	150	
		4	200	
	Orbit	0.5 - 0.75	60	4
		1 - 1.5	75	
		2	100	
		3	120	
		4	190	
		6	245	
		8	350	
		10	500	
		12	595	
		14	780	
	Plug	0.5 - 0.75	60	4
		1 - 1.5	75	
		2	120	
		3	150	
		4	200	
		6	255	
		8	300	
		10	394	
		12	480	
		14	560	
		16	640	
		20	800	
		24	960	
		30	1 200	
Vents		1 - 4	2 000	1
		6 - 30	5 000	

Appendix VII

Physical Acoustics VPAC Measurement

Valves can leak when the seat becomes damaged during repeated operation, or a deposit can make it impossible for the valve to close completely, or the valve can be scored allowing gas to pass when closed. Process relief valves or shutoff valves connected to vent and flare systems can gradually become degraded and allow gas to pass through the valve into the vent system.

Gas that leaks into the atmosphere from a component can be detected by many methods, but gas that leaks through a valve into a vent system can be very difficult to detect. Often, the only evidence of a leak is an increase in the flow to a flare. This increase in flow can be difficult or impossible to link to a source in a flare system that may have dozens or hundreds of pressure relief valves and valves connected to it.

To solve this problem, in 1985 BP commissioned the development and implementation of acoustic methods of gas leakage through valves. This work has been continued by Physical Acoustics Ltd, of Cambridge England who developed an intrinsically safe acoustic leak detector, the model 5131 VPAC. This instrument uses a sensor that is held against the pipe upstream of the valve, held to the valve and held to the pipe downstream of the valve. At each place the VPAC detects the level of sound in decibels. Valves that are leaking will have a larger signal than valves that are completely sealed. The rate of leakage through the valve is dependent on the size of pipe, size and type of valve, and the process pressure. Physical Acoustics has drawn on the years of field testing that BP conducted to develop correlations to allow leak rates to be determined from the measured sound signals.

The derived predictive equation is:

$$\begin{aligned}\log_{10}(\text{leak rate, lpm}) = {} & 0.168 + 0.0453 * (\text{signal level, dB}) \\ & - 0.286 * \log_{10}(\text{inlet pressure, barg}) \\ & + 0.936 * \log_{10}(\text{inlet size, ins NB}) \\ & + 0.568 \text{ (add only if gate valve)} \\ & -0.269 \text{ (subtract only for ball valve).}\end{aligned}$$

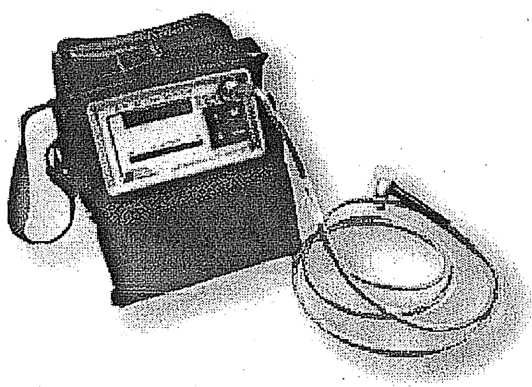

Figure VII-1 The VPAC 5131 Acoustic Leak Detector from Physical Acosutics.

Gas that leaks into a flare system unintentionally is lost product or if it is from a refrigeration system is gas that needs to be made up to keep the plant operating. In addition gas that is vented without combustion can add to greenhouse gas and VOC emissions, while hydrocarbon gases that are leaked to a flare or thermal oxidizer will add to the plants CO_2 emissions.

There are three types of leaks to determine what action is needed;

- Small leaks that are uneconomic to repair with the valves noted for continued monitoring.
- Significant leaks that will require the valve to be repaired or replaced at earliest convenient time.
- Very large leakers that require immediate repair to halt loss of lost product.

Often plant personnel suspect that there is a leak in part of the plant, or know that flow to a flare system cannot be accounted for by known plant operations. Previous surveys of the valves connected to vent systems has shown that between 5 to 10% of valves on gaseous/vapor service are passing, with a higher percentage for valves in suspected problem areas.

A survey of valves connected to the flare system was conducted as part of the Leak Detection and Repair survey for this plant. Plant personnel were consulted to identify areas where leaks were suspected to focus the survey, given the limited time that the LDAR team had on site. Plant operators were consulted to ensure that the leak detection did not interfere with plant operations, and to coordinate when flare systems were modified to facilitate leak detection.

Signal levels were recorded at the valves and the data used to determine leak rates. This leak rate had been used with the stream composition data to calculate the value of the gas that is passing through the valve, and the GHG emissions calculated.