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Economic Analysis of Distributed Control System (DCS) and Conventional System Flowstations

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Abstract

Economic evaluation is an essential step for assessing, studying and selection of distributed control system (DCS) flow station over conventional flow station. The flow station is a production plant that processes production fluid through a conventional flow station or a distributed control system (DCS). This study compared the economics and uncertainty analysis of both flow station type. The economic indicators (Net Present Value NPV, Internal Rate of Return IRR and Present Value Ratio PVR) of the conventional flow station ($893.44 million, 43.33% and 0.579) is more viable for oil and gas producers than the DCS flow station ($389.723 million, 23.33% and 0.162), but the uncertainty analysis shows that the convention flow station, has more risk and uncertainty associated with it. The conventional flow station is 6.59% higher in uncertainty than the DCS flow station. Oil and gas producers that are risk seeker will develop the conventional flow station with higher monetary and higher uncertainty than the DCS flow station. Risk averse oil and gas producers will develop the DCS to reduce operating expenditure and increasing the safety of the flow station facility and humans.

Keywords*: Conventional flowstation; Distributed control system Flowstation; Economic model; Risk; Uncertainty; Profitability indicators.*

1. Introduction

Crude oil and gas production have assumed a predominant role in the global economic frame work, providing much of the energy that drives the economy in both developed and developing countries. Oil and gas deposits are distributed around the world, existing in large quantities in various continents, from huge production fields in Alaska, Texas, Gulf of Mexico in North America, Venezuela, Brazil, Gulf of Guinea [1].

This has become the prime source of revenue to many countries, particularly in the developing countries. Organization of petroleum exporting countries (OPEC), has played a leading role in the global oil and gas industries, promoting market stability and ensuring steady flow of revenue accruing to member countries of the cartel. According to [2] reports, crude oil and gas, serves to boost economic growth and accelerated development; in others, it has heralded structural difficulties which have undermined economic performance and compounded development trends, with little real benefits for the majority of the people in the countries concerned.

Crude oil and gas have become the world's most strategic natural resources required as a crucial input in contemporary economic activities. A versatile, non-renewable natural resources, the (crude oil) is a highly demanded commodity in both rich and poor countries, providing about 50% of global energy requirements [3-4].

Nigeria as a Sovereign state has remained a point of reference in Africa and on the global stage. This stem from the fact that it is one of the longest exporters of crude oil to developed and developing nations of the world for more than three decades. Therefore, flow stations processing crude oil have been a major hub of the energy, revenue and foreign exchange earnings for the Nigerian economy. In spite of vast quantity of crude oil for exportation, 84.5% of the Nigerian population still lives below poverty line of US 1.25 a day [5].

According to [6], the flow station is usually the first processing facility for hydrocarbon fluids coming from the different wells. The hydrocarbon fluid enters the flow station via the inlet manifold to separator unit. The in-let manifold has been bulked, based on like pressures to ensure proper alignment of wells to designated headers to avoid back pressure effects. The well alignment process ensures that oil and gas wells of widely dissimilar pressures do not flow together as this would lead to backing out wells with lower pressures. The hydrocarbon fluid from the inlet manifold is directed into the separators (test separator, low pressure (LP) separator, medium pressure separator (MP) or high-pressure (HP) separator). There are HP and LP back pressure control valves used to regulate and maintain the station static pressure.

In the operation of separators [7], the stated that hydrocarbon separators, separate the hydrocarbon into total liquid and gas phases, reduces turbulence and allow the separated fluids to flow to the next unit. The gas flows to gas processing unit, where it is treated for utilization, either as instrument gas or sold to domestic consumers and power industries. Where the gas processing unit is not available, the gas flows to flare header, where it is flare in an open space, resulting to environmental pollution. The total liquid is moved to the surge tank, where it is then pumped to terminals (point of sale), through the lease automated custody transfer (LACT) unit. The LACT unit is mounted on skid and it is equipped with meters that measure the volume and quality (basic sediments and water (BS$W)) of crude oil leaving the flow station. This is necessary for both the sellers and buyers of the crude oil to guaranty trust.

The flow station can be simple or complex, depending on the technology on which the station is built. Advanced technologies and instrumentation are developed to enhance the production of hydrocarbon in the flow station. Flow stations can be conventional (simple) or distributed control systems (DCS) (Complex). However, both are used, but this work seeks to carry out economic and risk analysis to determine which flow station configuration and technology gives maximum return on investment and the risk associated with the technical and business operations. The analysis of this work will guide oil and gas mid-stream operators at the front end engineering design (FEED) stage, on which configuration and technology of flow station (conventional of DCS) to implement for optimum hydrocarbon separation, based on time, capital cost, operating expenses, ease of operations.

2. Operations of DCS and conventional flow station

In the early days of production of hydrocarbon into the flow station, all changes to process variables on a plant were carried out manually. For example, as stated in [8] report, if flow or level needed to be increased or decreased, an operator would be informed by the supervisor to go to the location of the flow or level control valve and adjust it accordingly. If there is high level on the surge vessel seen through the sight glass, the operator will manually control it by opening the discharge valve more or closing the inlet valves to control the surge vessel's level. This is type of process is usually associated with conventional flow stations and they are labour intensive. The conventional flow stations are equipped with certain control units are located on a central analogue panel called the Robert-Shaw panel. The flow station shutdown and start up control units are visible on the panel. (Green means healthy while red means faulty condition on the Robert-Shaw panel). In the event of mal-function or mal-operation, the operator physically checks the panel to identify which control unit has turned/flag red, indicating fault and the operator will determine further actions to be taken. Robert-Shaw panels are pneumatically operated.

The distributed control system is an easy-to-use automation system that simplifies operational complexity. It increases plant performance with intelligent control that is easy to operate and maintain. The operator knows the health of the flow station on demand, by viewing real-time process values, trends alarms historians and other key data from their screen.

3. Materials and methods

The economic viability of distributed control system (DCS) flow station to convention flow station is dependent on three major factors, namely: capital expenditure (CAPEX), operating expenditures (OPEX) and crude oil and natural gas prices. Excel spreadsheet and Model Risk simulator were utilized to develop economic model (cash flow) and risk model for the conventional and DCS flow stations.

Profitability indicators were estimated from the cash flow to ascertain the viability of the flow stations. Cash flow is the total inflow and out flow of funds over the life of an investment/project. The profit indicators evaluated from the cash flow model used for decision making for comparing distributed control system flowstation over conventional flow stations include, Net Present Value (NPV), Internal Rate of Return (IRR), Payback Period and Profit to Investment Ratio or Profitability Index (PI).

3.1. Net present value (NPV)

NPV also referred to as the present value of cash surplus or present worth, is obtained by subtracting the present value of periodic cash outflows from the present value of periodic cash inflows. It describes a measure of capital created over and above the hurdle rate. It is used to screen projects and rank alternative investments. To screen projects, those with NPV greater them zero (positive NPV), at handle rate are acceptable while, those with NPV less than zero (negative NPV) are rejected. In ranking alternative investments, project with highest NPV is best project among mutually exclusive investment opportunities.

Mathematically;

$$NPV = \sum_{t=0}^{n} \frac{(NCF)_t}{(1+r)^t} \tag{1}$$

3.2. Internal Rate of Return (IRR)

IRR measures the effective rate of return earned by an investment as though the money had been loaned at that rate. It describes the discount rate at which the NPV is exactly equivalent to zero. The IRR is used in screening projects to identify those that are to be accepted. If the IRR is greater than the hurdle, the project is accepted, otherwise the project is rejected.

3.3. Present Value Ratio (PVR)

The PVR is a dimensionless ratio of the present value of future operating cash flow for a project to the present value of total investment, the present value of benefits per present worth of every dollar invested in the project. The PVR is used for screening a project. In the screening process, project with PVR greater than 0 are accepted while, those with PVR less than 0 are rejected.

Mathematically;

$$PVR = \frac{NPV}{I_o} \tag{2}$$

3.4. Payback period

Payback period is defined as the expected number of years required to recover initial project investment. It is calculated based on the time required for the cumulative discounted net cash flow to be exactly equal to zero. Generally, companies prefer investment with a shorter payback period. Linear interpolation is done at the point where the cumulative net cash flow changes sign (from negative to positive), to obtain the payback time.

The risk associated with both flow stations type is modelled such that the CAPEX and OPEX are defined by triangular probability distribution functions, since the CAPEX is a one-off cost and the OPEX is a periodic expenditure over the life of the project. Oil price is defined by lognormal probability distribution function, since price of crude oil cannot be zero. Inflation is defined by Beta probability distribution function, since we are uncertain about the stability of the economy with respect to crude oil product price. The CAPEX, OPEX, oil price and inflation, form the input variables for stochastic in the risk model. Net Present value (NPV) and profitability index (PI), forms the forecast variables for the stochastic model.

Table 1 and Table 2 are the cash flow parameters used in estimating the profitability indicators. Table 1, shows the CAPEX and OPEX of the conventional and DCS flow stations, while Table 2 shows the common parameters used for both flow stations.

Table 1. Capital and operating expenditures for both flow stations

Conventional Flow Station			DCS Flow Station		
CAPEX	2400	$MM	CAPEX	1543	$MM
OPEX	2	$MM	OPEX	5.714	$MM
Inflation	15	%	Inflation	12	%

Table 2. Common parameters for the cash flow

Parameters	Values	Unit
Price		Unit
Crude oil	60	$/bbl
Natural gas	2.93	$/MScf
Production		
Crude oil	35000	bbl/d
Natural gas	3.5	MMScfd
Disc Rate	15	%
Fiscal Terms		
Tax	30	%
Royalty	12.5	%
Depreciation.	SLM	5 years
OP. Days	356	years

3.5 Model equations

Crude oil and natural gas production were estimated using exponential production decline rate equation (Equation 3).

$$q = q_0 e^{-at} \quad (3)$$

where q and q_0 are the production rate (bbl/d) for time (t) and the initial production rate (bbl/d) and a is the build-up rate, which lasted for three years the plateau stage of the production lasted for four years, before the wells started to yield to production decline.

In the cash flow model, the CAPEX was assumed to be 30% expensed and 70% capitalized which was depreciated over five years period using straight line method. The OPEX was assumed to be fixed for both flow stations type for the forecasted 10 years period of the project.

4. Results and discussions

Table 3, shows the estimated profitability indicators of the conventional and DCS flow stations. Although, both flow stations type meet the criteria (NPV > 0, IRR > discount rate, PVR > 0) for accepting a viable project, but the estimated NPV, IRR and PVR for the conventional flow station are all higher than those of DCS flow station, indicating that the conventional is more viable for investment than the DCS flow station. In addition, the payback time for the DCS flow station is higher than the conventional flow station, indicating that, it will take shorter time for investors to recoup their investment capital for conventional flow station than for DCS flow station.

On the basis of the cash flow model, oil and gas producers will, at the front end engineering design (FEED) stage, decide to design and install the conventional flow station, since it will yield maximum return on investment.

Table 3. Profitability indicators based on the cash flow for the flow stations

	DCS flow station			Conventional flow station	
Indicators	Values	Unit	Indicators	Values	Unit
NPV	389.723	(MM$)	NPV	893.440	(MM$)
IRR	23.33%	(%)	IRR	43.55%	(%)
PVR	0.162	(-)	PVR	0.579	(-)
Payback Time	6.54	(years)	Payback Time	3.62	(years)

The hydrocarbon, which leaves the well head enters the flow station. From the FEED stage to commissioning, start-up and operations of flow station for processing hydrocarbon, are all associated with risk. Therefore, the conventional and DCS flow stations designs and operations involves risk. This is the essence for the stochastic analysis of the project to ascertain the flow stations that involves more risk, which will help oil and gas producers to make proper decision before the design, procurement and installation of equipment.

The estimated NPVs are $389.723 million and $893.44 million for DCS and conventional flow stations. However, Figure 1, shows that there is less than 71.55% probability that the conventional flow station project will generate $893.44 million NPV, indicating that there is more than 28.45% of uncertainty in the input variables. Similarly, Figure 2, shows that the DCS flow station will yield an NPV of $389.723 million, for a probability of 78.14%, meaning that uncertainty of 21.86% is associated with the input variables.

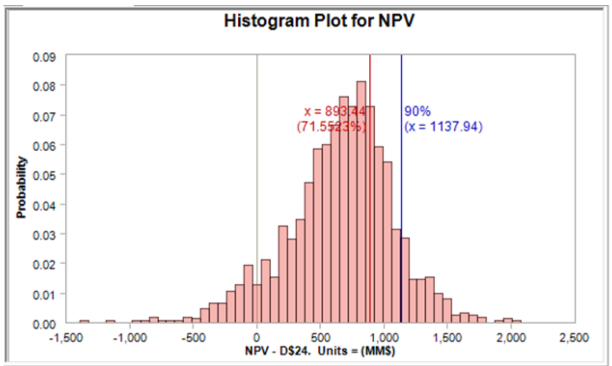

Fig. 1. NPV certainty plot for conventional system

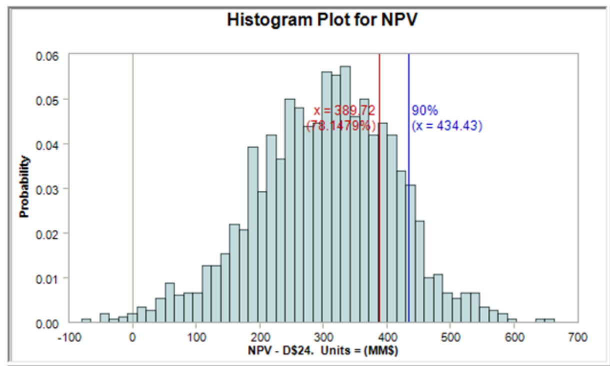

Fig. 2. NPV certainty plot for DCS system

The response of the PVR of the conventional flow station to changes in the input variables, shows that the conventional flow station will yield 0.58 PVR at a probability of 71.885% (Figure 3), with 28.115% uncertainty in changes of the input variables. The DCS flow station has 76.22% probability that the project will yield 0.16 PVR (Figure 4), and the uncertainty in the input variables is 23.78%.

In the PVR (which is the ration of NPV to capital cost for the project) response, the uncertainty may be a component (OPEX, CAPEX, etc) by which the NPV was evaluation.

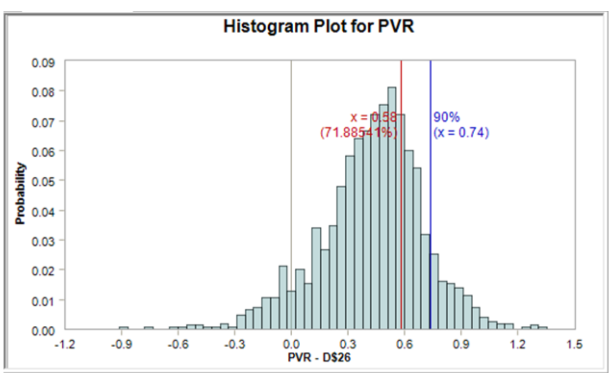

Fig. 3. PVR probability plot for conventional system

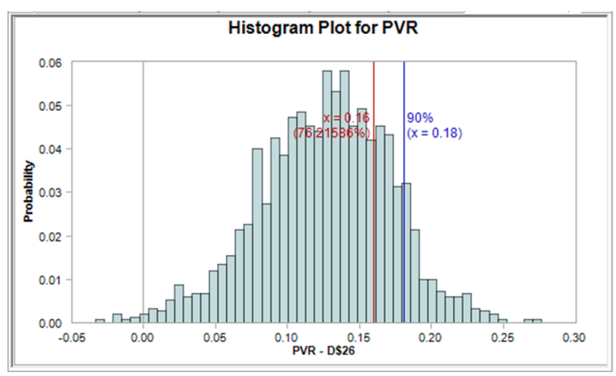

Fig. 4. PVR probability plot for DCS system

Though the deterministic model shows that the conventional flow station is more viable for investment by oil and gas producing companies than the DCS flow station, but the stochastic model has shown that there more risk associated with the conventional flow station than the DCS flow station. The NPV for the conventional flow station is 6.59% uncertainty higher than the DCS. The behaviour and response of oil and gas producers with respect to the uncertainty in these two flow stations will be different. Risk averse investors will prefer to invest in the

DCS flow station, rather than the conventional with higher risk and uncertainty. Whereas risk seeker will accept the conventional flow station and deal with the intention of reducing it.

The input variables that impact more on the conventional system, was determined by performing a sensitivity analysis on the stochastic model. These uncertainties in the input variables are impacted on the conventional and DCs flow stations, but each input variable has its different degree of impact of uncertainty on the project, determine via sensitivity analysis.

Figures 5 and 6 are the sensitive response of the NPV and PVR for the conventional flow station, and they show that OPEX has more impact of uncertainty on the conventional flow station. The other input variables (Inflation, crude oil price and CAPEX) impact minimum uncertainty on the project, as such their analysis of impact will be ignored and focus will be on the OPEX which has high uncertainty on the project.

The uncertainty in OPEX may be due to high cost of handling man power and frequent maintenance of equipment in the stations. In addition, high cost of handling man power also, increase the cost of consumables, such as staff warfares.

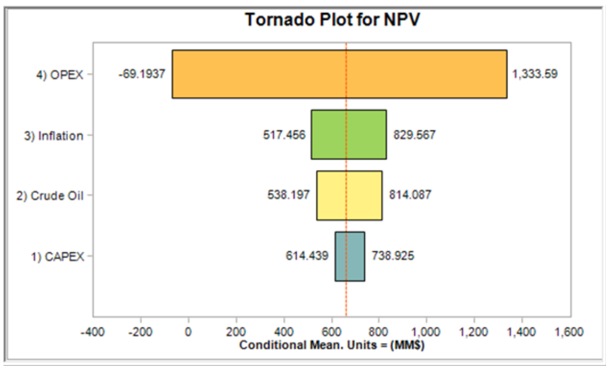

Fig. 5. Tornado plot for NPV of conventional flow station

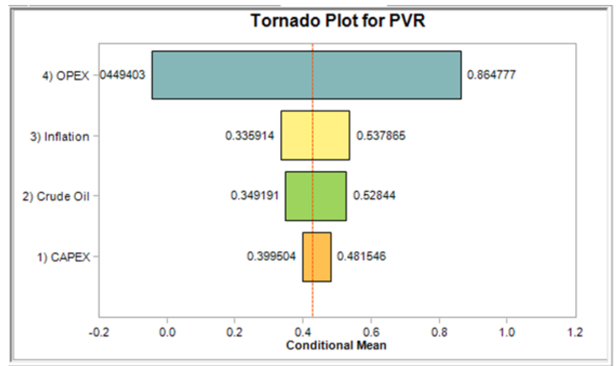

Fig. 6. Tornado plot for PVR of conventional flow station

The NPV and PVR of the DCS flow station, shows a sensitive response of high uncertainty in OPEX and oil price and other parameters shows minimal uncertainty, which will be ignored in this analysis (Figures 7 and 8).

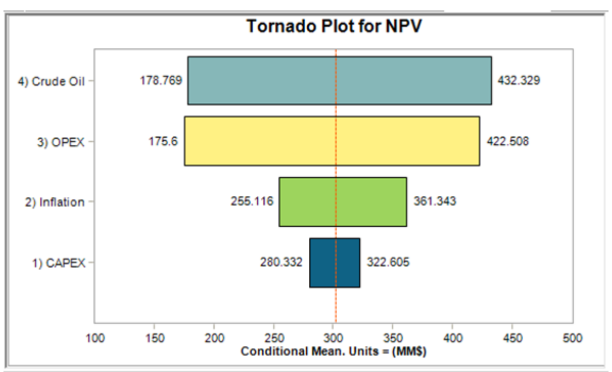

Fig. 7. Tornado plot for NPV of DCS flow station

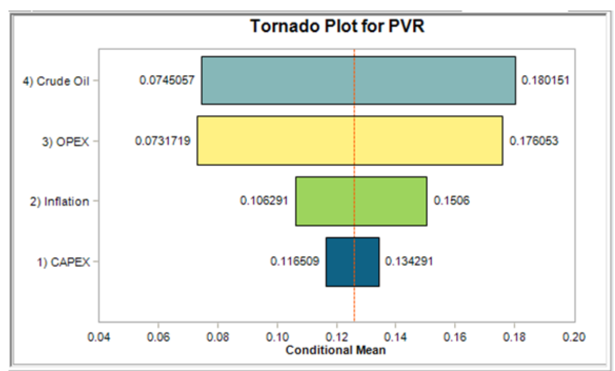

Fig. 8. Tornado plot for PVR of DCS flow station

A distinction between the uncertainty in the OPEX and the oil price must be stated here. Increase in the OPEX, will decrease the NPV and PVR (negative uncertainty). Operating expenditure tends to increase, if production must increase, thereby reducing the monetary return. Management may tend to reduce operating expenditure by reducing the number of man power and consumables. In addition, new technology is one of the main reasons for the increase in safety, efficiency and economy of the oil and gas industry. To meet this requirement, automatic control systems were devised and as these systems were developed, the labor required to run a plant decreased correspondingly. The NPV and the PVR will increase, if the oil price increases (positive impact). Thus, oil and gas producers enjoy high return on investment when oil price is increasing.

5. Conclusion

At the onset of producing a newly drilled wells, oil and gas producers are faced with a decision of the configuration of the flow station that will handle the produces hydrocarbon. However, this may be dependent on many factors, but this paper which is based on economic and uncertainty analysis has shown that conventional flow stations are more viable for processing hydrocarbon than the distributed control system flow station, but the conventional flow station is bedeviled more uncertainty than the DCS flow station. Oil and gas producers that are risk seeker will develop the conventional flow station with higher monetary and higher uncertainty than the DCS flow station. Risk averse oil and gas producers will develop the DCS to reduce operating expenditure and increasing the safety of the flow station facility and humans.

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