Artificial Lift Methods Overall Comparison

	Rod Pumping	ESP	Jet Pump	Gas Lift
World wide Market	The most popular artificial lift system, 40%.	18% of total population.	1% of total population.	The most popular artificial lift system after Rod pump, 34% of total population.
Capital Cost	Low to moderate. Cost increase with depth and larger surface units.	High for power generation and cabling. Relatively low capital cost if electric power available. Costs increase as horsepower increase.	Relatively low to moderate. Cost increases with higher horsepower. Wellhead equipment has low profile. Requires surface treating and high pressure pumping equipment.	Well gas lift equipment cost low, but compression cost and gas distribution system may be high. Central compression system reduces overall cost per well.
Operating Cost	Low for shallow to modium depth (<7000 ft) and low production (<400 bfpd). Units easily changed to other wells (re-use) with minimum cost.	Moderate to high. Costly interventions are required to change out conventional ESP completion. Varies if high horsepower, high energy costs. High pulling costs results from short run life. Repair cost often high, but productivity and improved run life can offset these costs.	High power cost due to horsepower requirment to pump power fluid. Low pump maintenance cost with properly sized throat and nozzle for long run life. No moving parts in pump, simple repair procedures.	Low, Gas lift systems have a very low OPEX due to the downhole reliability. Well cost low. Compression cost vary depending on fuel cost and compressor maintenance.
Down Hole Equipment	Reasonably good rod design and operating practices needed. Good selection operating and repair pracices needed for rods and pumping.	Requires proper cable in addition to motor, pumps seals, …etc. Good design plus good operating practics essential.	Requires computer design programs for sizing. Tolerant of moderate solids in power fluid. No moving parts in pump, long service lift. Simple repair procedures to run and retrieve pump downhole.	Good valve design and spacing essential. Moderate cost for well equipment (valves & mandrels). Typically less than "5" valves needed. Choice of wireline retrievable of conventional valves.
Facilities footprint	Small footprint on surface. Facilities often have power generation already installed; hence the addition of power for a rod pump unit does not have as large an impact as for gas compression.	Facilities often have power generation already installed hence the addition of power for ESP does not have as large an impact as for gas compression.	Large amount of surface spacing is require. Surface unit can be mounted on one skid or two skids for a dualvessel power fluid cleaning unit.	Large amount of space is required to install a compression system.
Efficiency (Operating).	Excellent total system efficiency. Typically 50 to 60%.	Good for high rate wells, but decrease significantly for <1000 BFPD. Typically total system efficiency is about 50% for high rate wells but for <1000 BPD, efficiency typically <40%.	Fair to poor, maximum efficiency for ideal case is 30% thus power fluid at 2-3 times the produced fluid rate is required. Heavity influenced by power fluid plus production gradient. Typically operating efficiency of 10 to 20%.	Increases for wells that require small injection GLR's. Low for wells requiring high GLR's. typically 20 to 30%.
Flexibility	Excellent, can controll production rate.	Poor, for fixed speed. Requires careful design VSD provides better flexibility.	Good to excellent, power fluid rates and pressure adjusts the production rate and lift capacity from no-flow to full design capacity of installed pump selection of throat and nozzle sizes extend range of volume and capacity.	Excellent, gas injection rate varied to change rates. Tubing needs to be sized correctly.
Reliability	Excellent: run time efficiency >95% if good rod practices followed.	Varies, excellent for ideal lift cases, poor for problem areas (very senstive to operating temperatures and electrical malfunctions).	Good with proper throat on nozzle sizing for operating conditions. Must avoid operating in cavitation range of jet pump throat, related to pump intake pressure. More problems if pressure >4000 psi.	Excellent if compression system properly designed and maintained.
System (Total)	Straight foreword and basic procedures to design, install & operate following API and RP's. Each well is an individual sestem.	Fairly simple to design but requires good rate data system not forgiving, requires excellent operating practices follow API, RP's in design testing and operation. Each well is an individual procedure using a common electric system.	Available computer design program for application design. Basic operating procedure for downhole pumpand well site unit. Free pump easily restricted for on-site repair. Downhole jet often requires trial and error to arrive at best/optimum jet.	An adequants volume, high pressure, dry, non-corrosive and clean gas supply source is needed through out the entire life. Good data needed for valve design and spacing. API space and design/operating RP's should be followed.

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Usage / Outlook	Excellent, used on about 85% of USA artificial lift wells. The normal standard artificial lift method.	An excellent high rate artificial lift system. Best suited for <200 dgree F and >1000 BFPD rates. Most often used on high watercut wells	Good for higher volume wells requiring flexible operation wide depth range, high temperature, high corrosion, high GOR, significant sand production.	Good, flexible, high rate artificial lift system for wells with high bottom hole pressures. Most like a flowing well.
Volume high lift capabilities	Fair, restricted to shallow depths using large plungers. Maximum rate about 4000 bfpd from 1000' & 1000 bfpd from 5000'.	Excellent, limited by needed HP and can be restricted by casing size. Tendom motors can be used to increase HP but also increase operating costs.	Excellent, up to 15,000 BPD with adequate flowing bottom hole pressure, tubular size and HP.	Excellent, restricted by tubing size and injection gas rate and depth.
Volume low lift capabilities	Excellent, most commonly used method for wells producing <100 bfpd.	Generally poor, lower efficiencies and high operating costs <400 BFPD.	Fair, >200 BFPD from 4000 feet.	Fair, limited by heading and slippage. Avoid unstable flow range. Typically lower limit is 200 BFPD for 2" tubing and 700 BPD for 3" tbg. Intermittent gas lift system is better for low volume.
Production rate range	Rate is dependent on setting depth. Feasible for low rates (<100 b/d) and low GOR (<250). In general due to efficiency, rod pump is not recommended as a lift mechanism of choice on high producing wells.	The full range of production rates can be handled. When unconstrained an ESP can be designed to produce the full well potential to the surface (AOF), thus achieving higher flow rates than gas lift.	The full range of production rates can be handled. Less than 50 BPD up to 15,000. AOF production rate cannot be achieved.	The full range of production rate can be handled. An AOF production rate cannot be achieved with gas lift because as mush drawdown as for an ESP cannot be achieved.
Flowing bottom hole pressure	The pump depth and the dynamic head restrict achieving a low FBHP. The excellent result can obtain at intake pressure less than 25 psig providing adequate displacement and gas venting, typically about 50 to 100 psig FBHP.	Achieving any FBHP is not a constraint with ESP. AOF can be achieved if the well and reservoir properties do not constrain the ESP design.	For range of 100 to 1000 psi, Typical design target is a minimum of 100 psi per 1000 feet of lift. Intake pressure should be >350 psi to 5000 ft with low GLR. For BHFP less than 100 psi, jet pump cannot deliver fluids to surface.	If the FBHP is greater than 1000 psi, the efficiency of the gas lift determines the achievable FBHP. A gas lifted well normally works with FBHP in this range. For range 100 to 1000 psi FBHP, gas lift can work in the upper end of this range for low reservoir pressure and productivity wells, however there needs to be enough reservoir energy to deliver the produced fluids to the surface. Less than 100 psi FBHP, gas lift cannot deliver fluids to surface.
Drawdown	The pump depth and the dynamic head limit acievable drawdown.	Any drawdown can be achieved with a given ESP design, however well and reservoir constraints limit final drawdown.	Good drawdown but cannot completely deplete a well.	Achievable drawdown is limited by ability to lightern head of fluid above gas lift point. AOF can never be achieved.
Flow stability	Not recommended for unstable flow.	Not recommended for unstable flow.	Continuous and smooth flow of produced fluids.	Gas lift able to handle all types of flow regimes by they stable or unstable.
Recovery	Recommended for primary and secondary waterflood.	Recommended for primary and secondary waterflood.	Recommended for primary and secondary waterflood.	Recommended for primary and secondary waterflood. However high watercut reduces the ability to move large fluid volumes.
Pressure support (Constant Ps)	Recommended for constant Ps.	Recommended as an ESP is able to move the same fluid volume no matter what watercut.	Recommended, as jet pump system is independent of watercut % producing from a well.	Well suited, however increasing watercut reduces the ability to move large fluid volumes.

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	Rod Pumping	ESP	Jet Pump	Gas Lift
Reservoir pressure decline	If there is no pressure support from the reservoir, production rate will decline and the well will be "pumped-off".	Not recommended when there is significant pressure drop, the range of production rates that a particular ESP design can handle is limited. Hence the reservoir condition rate of change would define the ESP change out frequency rather than ESP mechanical run life. Variable frequency drives (VFD) allow some operational flexibility on matching the production rate to the ESP design.	Not recommended when there is significant pressure drop in the reservoir, the range of production rates that a particular jet pump design can handle is limited. A new jet pump design needs to be in placed to get optimum lift for the well.	Recommended as the flexibility of gas lift allows one installation to deal with falling pressure and production rates.
Water Cut	Recommended for the full range of watercut.	Recommended for the full range of watercut. The ESP is largely insensitivt to increasing watercut.	Recommended for the full range. High water production may increase the operating cost.	High watercut may reduce efficiency due to heavier column of fluid to lighten. May not be able to lift well if reservoir pressure is low.
Gas oil ratio	Feasible for low rate and low GOR (<500 scf/stb). For range 500 to 2000, Gassy wells usually have lower volumetric efficiency. Gas handling ability is rather poor if one has to pump >50% free gas. If the gas anchor or natural separation is used and free gas is venting, the volumetric efficiency can be significantly improved. Not recommended for GOR greater than 2000 scf/stb.	Recommended for Less than 500 scf/stb. Problems with gas breakout in the pump will be minimised. For range 500 to 2000 scf/stb, the achievable pump rate will be limited by the amount of gas breaking out of solution in the area of the pump. An ESP can be designed to a free gas volume handling criteria. Down hole gas handling equipment may be incorporated into the completion. Greater than 2000 scf/stb, FBHP will need to stay above the bubble point pressure to avoid gas cavitation in the pump.	Target design is less than 1000 GLR. Not recommended for GOR greater than 2000. Gas above 2000 scf/stb substantially reduces efficiency but helps lift. Vent free gas if possible. The producing of free gas through the pump causes reduction in ability to handle liquids.	Recommended for full ranges. Gas lift would be only expected to be of benefit at higher GOR.
Bubble point	Not highly recommended for high bubble point. Recommended for low bubble point.	Not recommended for high bubble point, as this will limit the maximum drawdown in the well due to the detrimental effects of free gas in the pump. Recommended for low bubble point, hence the FBHP can be low allowing more production without the affects of free gas in the pump region.	Not recommended for high bubble point. Recommended for low bubble point.	Recommended for all bubble points. Gas lift not dependent on the bubble point pressure hence is suitable for any range.
Gas coning	For gassy reservoir, Rod pump handling is fair to good.	Not recommended	Not recommended. Cavitation in jet pump likely.	Gas lift can be effective in producing a well that cones gas.
Water coning	Rod pump can be effective in producing a well that cones water.	ESP can be effective in a well that cones water, but may allow more water to produce rather than oil.	Jet pump can be effective in a well that cones water.	Gas lift can be effective in a well that cones water.
Oil gravity	>8^ API.	No limitations Preferable >12 API.	>8 to 45 API.	No limitations. Preferable >15 API.
Fluid viscosity	Recommended for less than 100 cp gas free viscosity at reservoir temrature. Good for <200 cp fluids and low rate. Rod fall problem for high rates. Higher rates may require diluents to lower viscosity. Not recommended for greater than 500 cp, as pump efficiency will reduce.	Recommended for less than 100 cp gas free viscosity at reservoir temperature. 100 to 500 cp will reduce the efficiency of ESP. Not recommended for greater than 500 cp, as the motors cool poorly in the high viscous fluid, more power is required to pump high viscus fluid and emulsions form.	The system is capable of handling high-viscosity fluid.	Has been used with success up to 1000 cp but little case history for very high viscosity.

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Safety	Workovers to change out rod string could be required every 1-1/2 year. If it is highly deviated well, frequent workovers could be required to fix broken rod string. As frequent as once every 6-8 months.	Full workover could be required every two years (industry average), hence safety risk is higher than gas lift. Electrical fire risk is increased.	More risk of injection and production lines rupture.	Safety risk is low. More risk of blow out and gas fire with hifh-pressure gas lines required.
Intake capabilities	Excellent: <25 psi provided adequete displacement & gas venting. Typically about 50 to 100 psig.	Fair if little free gas (I,e <250 psi pump intake pressure). Poor if pump must handle above 5% free gas.	Poor to fair, > 350 psi to 5000 ft with low GLR.	Restricted by the gradient of the gas lifted fluid. Typically moderate rate is limited to about 150 psi per 1000 ft of injected depth. Thus, the back pressure on 10,000' well may be >1500 psi.
Surveillance	Excellent: can be easily analyzed. ?Improved analysis by use of dynamometers and computers.	Fair, electrical checks but special equipment needed otherwise.	Good/fair, down hole performance can be analyzed from surface power fluid rate and pressure, SPM and producing rate. Pressure record can be run and retrived on free pump.	Good/excellent, can be analyzed easily. BHP and production log survyes easily obtained. Optimization and computer control being attempted.
Reservoir access	No reservoir access. Cnnot run any type of surveillance log.	Downhole ESP equipment restricts access. A logging bypass can be installed but this complicates the equipment and downsizes the ESP. Remedial work requires a full workover. Coil tubing deployed ESP can solve some reservoir access problems, but pulling the ESP would be required.	Good. If set in a sliding sleeve, the jet pump can be retrieved by wireline allowing access to reservoir.	Gas lift results in simple completions that allow ready access to the reservoir for surveillance and remedial work.
Number of welis	Recommended for single or more.	Recommended for single or more. Cost of power equipment will be reduced and rationalised as the number of wells completed increases.	Single wells are the most common. Multiple wells operating from one single surface hydraulic package greatly reduces lift cost.	As the number of wells increases the cost of the compression facilities becomes more economic on a well by well basis.
Well intervention	Workover or pulling rig. Run time efficiency is greater than 90% if good operating practices are followed and if corrosion, wax, asphatenes, solid, etc.. Are controlled.	Change out of total completion required for ESP failure. Average run life approximately two years. Remedial work will require completion to be removed.	A free jet pump can be circulated to the surface without pulling the tubing or it can be retrieved by wireline.	For gas lift valve changeouts slick line intervention >5 years.For remedial work as required with the ability to perform through tubing workovers.
Well inclination	Well suited to vertical wells. Not highly recommended for deviated. Slanted and crooked wells present a friction problem. There are increased load and wear problems in high angle deviated holes (>70^). Not recommended for horizontal well.	Well suited to vertical wells Good for deviated, requires long raduis wellbore bends to get through.	Excellent, for vertical or deviated completion.	Excellent, for vertical or deviated. Few wireline problems up to 70 degree deviation for wireline retrievable valves.
Duals completion	Not recommended.	A complicated system is required. Larger casing require. Possible run & pull problems.	Not recommended.	Historically wells are successfully completed as multi-string with gas lift. The optimum is apply continuous system in one side and intermittent system in other side.
Start up	Once power is available to the facility, rod pump system will be able to be run.	Once power is available to the facility, ESP systems will be able to be run.	Requires some fluid (water or oil) to fill the vessels as power fluid prior to start up.	Gas should be available after a shut down. Gas can be sourced from produced gas from naturally flowing well or artificially lifted by non gas lift method, or from a flowing gas well, or importing gas from an external source e.g. pipeline.

Artificial Lift Methods Overall Comparison

	Rod Pumping	ESP	Jet Pump	Gas Lift
Depth limit	For less than 2500 ft, pump must be landed below dynamic fluid level. Optimal to have intake below perforations, which allow natural gas separation and vent to annulus. Depth is tied to dynamic fluid level. Maximum depth is 14,000 ft TVD. Due to excessive polished rod load, depth is limited. Rods or structure may limit rate at depth.	Not restricted by well deptt. Usually limited to motor horsepower or temperature. Practical depth about 10,000 ft.	Not restricted by well depth. However limited by power fluid pressure or horsepower as depth increases. Practical depth 20,000 ft.	Not restricted by well depth. Controlled by system injection pressure and both gas and fluid rate.
Casing size limit (7") & Restricts tbg size.	Problems only if high rate wells requiring large plunger pumps. Small casing sizes (4.5" & 5.5") may limit free gas separation. There is a limitation of downhole pump design in of downhole pump design in small diameter casing.	Casing size will limit use of large motors and pumps. ESP restricted to a maximum diameter of 5.4" with a maximum flow rate of 12,000 BPD.	Small casing size limits producing rate at acceptable pressure droplevel. Jet pump is recommended for 7" casing.	Production tubing restricted to 4" tubing when installing side pocket mandrels.
Temperature limitation	Operating temperature range from 0 to 550^f. Can lift high temperature and viscous oils.	Limited to <250 degree for standard.	Excellent, possible to operate to 500 degree F with special materials.	Recommended for all temperature. Need to know temperature to design bellows changed valves.
Gas handling ability	Good if can vent and use gas anchor with proper designed pump. Poor if must pump (>50%) free gas.	Poor for free gas (I.e, >5% through pump). Rotary gas separators helpful if solids not produced.	Good/fair, may require suitable downhole gas separator below pump intake. Free gas reduces efficiency but helps lift. Vent free gas if possible. Use a gas anchor.	Excellent, produced gas reduces for injection gas.
Corrosive fluid (Corrosion handling ability)	Good to excellent. Using corrosion-resistant materials in the construction of subsurface pumps.	Fair. Run life will be shortened in a more aggressive environment. Special metallurgy and elastomers will be required leading to more costly equipment.	Good/excellent, using special metallurgy and/or chemical treatment. Chemical in the power fluid can treat the tubular for corrosion. Inhibitor fluid mixes with produced fluid at entry of jet pump throat.	Recommended. Compatibility of metallurgy and elastomers with the total completion is only required. Inhibitor in the injection gas and/or batch inhibiting down tubing feesible. Steps must be taken to avoid corrosion in injection gas lines.
Sand & solids handling ability	High solids and sand production is troublesome for low oil viscosity (<10 cp) Improved performance can obtain for high-viscosity (>200 cp) cases. May be able to handle up to 0.1% sand with special pumps.	Poor, requires <100 ppm solids. Sands at this cocentration is normal wear and tear for an ESP. Not recommended for greater than 100 ppm, due to friction and wear on ESP equipment.	Fair to poor. Operating with 3% sand. Fresh water treatment for salt build up possible.	Excellent, recommended for all wells producing sand. Sand has little effect on ability to a gas lift well.
High viscosity fluid handling capability	Good for up to <200 cp viscosity fluids and low rates (400 bfpd). Rod flil problem for high rates. Higher rates may require diluent to lower viscosity. For greater than 500 cp, not recommended, as pump efficiency will reduce.	Fair, limited to about 200 cp.	Good/excellent, >6 degree API production with <800 cp possible, power oil of >24 degree API and <50 cp or water power fluid reduces friction loss.	Fair, few problems for ~16 degree API or below 20 cp viscosity. Excellent for high watercut lift even with high viscosity oil.
Scale handling capability	Good to excellent. Batch treating inhibitor down annulus feasible.	If the well is prone to scale, paraffin or asphaltenes deposits then it is likely to occur in the pump area (larg pressure drop). This will lead to pump inefficiency, increased wear & tear and eventually failure. Chemical treatment is required to prevent formation of these contaminations.	Scale could build up at intake and nozzle over time but can be treated.	Scale can form close to the operating gas lift valve due to the pressure drop at that location. This may lead to blockage of the gas lift valves and an inability to be able to retrieve them

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	Rod Pumping	ESP	Jet Pump	Gas Lift
Paraffin handling capability	Susceptible to paraffin problems. Hot water/oil treating and/or uses of scrapers possible, but they increase operating problems and costs.	The same like scale.	Good/excellent. Circulate heat to downhole pump to mimimize build up (hot water/oil treatment), mechanical cutting and inhibition possible.	Paraffin may deposit near an operating gas lift valve due to temperature and pressure drop. This may lead to blockage of the gas lift valves and an inability to be able to retrieve them.
Asphaltene	Can be treated.	The same like scale.	Difficult to control.	Introduction of lift gas into the produced fluid stream may increase the risk of asphaltene deposits. Production chemistry analysis for individual fields will determine whether this is likely to occur.
Treatment (Scale & Corrosion inhibitor)	Corrosion and scale treatments easy to perform. Good batch treating inhibitor down annulus used frequently for both corrosion and scale control.	Materials design will need to be modified to ensure continued service of the ESP after treatment.	Corrosion/scale ability is good. Inhibitor with power fluid mixes with produced fluid at entry of jet pump throat. Batch treat down annulus feasible.	Recommended when any treatment is required. These treatments have little to no effect on a gas lifted system.
Electrical power	Can use electricity as power source. Prime mover flexibility is good: either engines or motors can be used easily (motors more reliable and flexible).	A source of electric power is needed. This can be a tie in to an existing facility, a tie in to a power grid or independent power generation.	A diesel or gas engine can be used where electricity is not available.	Not required.
Gas source	Gas engines could be used in locations with no electricity.	Does not impact ESP solution.	Does not impact JP solution. However, produced gas from the well can be used to power a gas engine prime mover.	Recommended, if a gas source is readily available either from produced gas, import gas or a gas well.