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Simulation-Driven Optimization of Simultaneous Frac Execution Strategies: Trade-Off Analysis of 2- And 3-Well Simul-Frac, Cost Models, Operational Efficiency, Flow Rates, and Stage Lengths

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Abstract

Simultaneous fracturing operations (i.e., simul-frac'ing) can offer efficiency gains by distributing total flow across multiple wells, reducing pipe friction, and increasing combined flow rate for an equivalent hydraulic pressure limit. However, the need to maintain a minimum rate per cluster and/or perforation friction often requires reducing clusters per stage, leading to more stages for the same lateral length. This increase leads to more plugs, wireline runs, stage breakdowns, flushes (i.e., pumping minutes when sand is not being pumped), and additional mill-outs. Further, pumping services contracts vary in charging day rates, inactive/standby rates, and/or active pumping hour rates—the latter can vary per stage or pad-to-pad based on pumping pressures and/or flow rates. These factors introduce a complex set of tradeoffs between energy efficiency gains and operational penalties. This paper shifts the focus from generalized simul-frac theory to a replicable, quantitative workflow using completions-process simulation software. By simulating multiple real-world design and operational strategy permutations, including contract-specific costs and performance constraints, engineers can economically optimize simul-frac implementation. The process transforms a traditionally experience-heavy domain with low-fidelity models into a structured, data-rich decision space applicable across operators and basins. Further, this paper adds evidence to the proposition that hydraulically fracturing wells simultaneously, in general, offers the unconventional resource industry significant efficiency gains. This paper's specific scenarios document, relative to non-simul-frac, Frac Phase cost savings of approximately 6.5-10.5% and completed lateral length per day increases of approximately 60-140%.

Background

Hydraulic fracturing (i.e., frac'ing) multiple wells simultaneously (i.e., simul-frac'ing) has steadily increased as a standard practice amongst unconventional operators [Bullinger and Reist (2021); Kim et al. (2021)]. Operators report efficiency gains in terms of both reduced completion costs and compressed completion cycle time compared to traditional single/zipper sequencing [Kim et al. (2021); *JPT* (2025)]. These gains stem from operating multiple wells in parallel, which—for a given maximum allowable hydraulic pressure—can also reduce friction losses in the wellbore system by distributing flow, thereby increasing the fraction of hydraulic energy delivered to the fractures [Navaiz et al. (2023); Bullinger and Reist (2021)].

The operational change of frac'ing one versus multiple wells has numerous cascading implications, especially in plug-and-perf operations. Simul-frac'ing operations can offer efficiency gains by increasing combined flow rate for an equivalent hydraulic pressure limit [Bullinger and Reist (2021)]. However, the need to maintain a minimum rate per cluster and/or perforation friction can require reducing the number of clusters per stage; this, in turn, tends to increase the total number of stages over a given lateral length [Lorehn et al. (2024); Dontsov et al. (2024)].

The increase in stages per well leads to more plugs, additional wireline runs, stage breakdowns, flushes (i.e., pumping minutes when sand is not being pumped), and extra mill-out operations. The fact that pad designs may combine simul- and non-simul operations—or mix two- and three-well simul configurations —further compounds the combinatorial complexity of completions planning.

Realized gains from simul-frac depend heavily on pad layout, fleet capability, and supply chain constraints. Studies and case reports consistently find the largest time savings on large multi-well pads (≥4 wells) or via remote simul-frac linking smaller pads [Street (2023); *JPT* (2025)]. One controlled field study compared a four-well pad completed with single/zipper versus simul sequencing and found that the simul pad completed in five fewer days and enabled more lateral footage with the same crew [Kim et al. (2021)]. In the Delaware Basin, candidates for simul-frac operations were identified considering pad geometry, spacing, and logistical constraints; remote simul execution strategies were proposed to enable efficient completions across uneven pad sizes [Street (2023)]. As simul-frac has matured, adoption has expanded into "trimul-frac" (i.e., three-well simultaneous completions), with several operators now adopting three-well simul-frac as a new standard in select plays [*JPT* (2025)]. These multi-well strategies, however, come with increased demands on horsepower, consumables throughput, wireline coordination, and control systems.

These operational and logistical tradeoffs—between energy efficiency gains and incremental penalties —make quantifying cycle time and cost impacts essential. This paper illustrates a reproducible method, using commercial completion simulation software, for performing such an economic-operational tradeoff analysis.

Definitions

Detailed, precise quantitative analysis requires precise terminology. The industry can often use the same word(s) for different, e.g., types of operations. Some terms with accompanying explanation and definitions are provided.

Pad: In this paper, the word "pad" specifically has in mind the set of wells being completed and brought online together more-so than a specific geographical location. E.g., a geographical location may have more wells/wellheads than are currently being completed, or a pad-connect may have sets of wells in relatively disparate geographic locations being completed together. "Pad" will be shorthand for the set of wells being completed together.

Frac Interval: A defined set of time (from pumps on to pumps off) during which a portion of subsurface (one or more well-stages) is hydraulically fractured.

Single-frac: In this paper, the term "single-frac'ing" or "one-well frac'ing" will refer to hydraulically fracturing a single well-stage at a time. I.e., there is one well-stage per frac interval. This contrasts with "simul-frac" where more than one well-stage is being hydraulically fractured at a time. I.e., single-frac'ing does <u>not</u> necessarily mean "frac'ing a one-well pad." One regularly single-fracs a multi-well pad. Some refer to this concept as "zipper frac'ing;" the authors' reasons for not using that phrase for this idea is in that term's definition.

While not common, when thinking of general names, it is reasonable to speak of "1-well simul-frac" as synonymous with single-frac.

N-Well Simul-frac: "Simul-frac'ing" refers to hydraulically fracturing one more than one stage at a time. I.e., there is more than one well-stage per frac interval. Each well-stage in a single-frac interval must be in a unique well. Some limit the phrase "simul-frac'ing" to specifically 2-well simul-frac. 3-well simul-frac is, in turn, referred to as triple- or trimul-frac. The authors prefer to refer to N-well simul-frac (where "N" can be any integer number) to increase precision and to remain open to future possibilities. E.g., especially for single-point entry designs, one may be interested in 4-well simul-frac and beyond.

Zipper Frac: The term "zipper frac" is commonly used to refer to frac'ing a well while, at the same time, running wireline, setting a plug, firing shots, and pulling out-of-hole (i.e., plug-and-perf'ing) a different well. Clearly it requires more than one well on the pad and allows for pumping and wireline operations to alternate between the wells. This process innovation greatly reduces cycle times for plug-and-perf operations by maximizing parallel activities. In this sense, zipper frac'ing contrasts with "stack frac'ing"—where the plug-and-perf and frac'ing activities continue to operate on the same well, effectively forcing each to wait on each other. These are the definitions used in this paper.

More recently, "zipper frac" has been used synonymously with "frac'ing one well at-a-time" (as "single-frac" is defined above). In this sense, "zipper frac" is in contrast with "simul-frac." This is likely because "single-frac" sounds too like the common expression "single-well ops," referring specifically to one-well pad completions where plug-and-perf and frac operations are having to wait on one another (stack frac). This use of zipper has not been used because one needs to distinguish between simul-frac operations that are alternating with plug-and-perf operations (zippering) and those waiting on plug-and-perf operations (stacking). I.e., the industry needs language to describe zipper simul-frac'ing and stack simul-frac'ing—which is not possible if "zipper" is used to mean "not simul."

E.g., a 4-well pad can be 2-well simul-frac'ed using zipper operations. If a 3-well pad is to be continuously 2-well simul-frac'ed, stack operations would have to be used (because a set of plug-and-perf activities would have to be waited on) to keep simul-frac'ing. In the 2-well simul-frac, 3-well pad case, an operator would need to choose between two options.

A. continuous "round-robin" simul-frac operations which would result in continual stack operations
B. 2-well + single-well frac'ing (2-well simul-fracing two wells and single-frac'ing one well), resulting in continual zipper operations

In general, if one is performing an N-well simul-frac (where N is any integer), if the pad contains fewer than 2*N wells, the operator will have similar options available to them.

More formally, define W(M) as the set of wells being frac'ed in frac interval F(M). An operation is defined as "zippering" if and only if no well is common to both intervals F(M) and F(M+1). I.e.

$$W(M) \cap W(M+1) = \emptyset . \tag{1}$$

It is important to note that pads can and often do have a mixture of stage-to-stage zipper and stage-to-stage stack operations. Service provider contracts may or may not adjust their pumping charge per hour based on the operations and, if they do, may or may not apply it differently stage-to-stage.

Stack Frac: The term "stack frac" refers to stage-to-stage operations where two consecutive frac intervals include the same well. In this sense, stack frac is in contrast to zipper frac. Formally, its definition is as follows.

$$W(M) \cap W(M+1) \geq 1. \tag{2}$$

Coupled Simul-frac: When N wells are simultaneously fractured and both the operations and contracts are coupled, that operational strategy is called "coupled simul-frac."

Coupled Operationally: The N well-stages being simultaneously fractured have "very similar" pumps-on time, pumps-off time, treatment flow rate (m^3/min, bbl/min), and slurry concentration (kg/m^3, lb/gal). This usually means the stages have very similar stage designs, but some operators, e.g., creatively adjust stage lengths to enable coupled simul-frac of stages with different, e.g., sand loadings (t/m, lb/ft). E.g., the designed/planned start times, stop times, total sand/stage, and total water/stage will be within approximately 5%. Wellhead treating pressures are typically allowed to vary more than this.

Coupled Contractually: When N well-stages are simultaneously fractured, they are billed by the operator as a single-frac interval. The N well-stages share pumping duration, pumping pressure, and their respective per-well flow rates are combined to determine the frac interval's flow rate. E.g., if two well-stages are coupled simul-frac'ed, each at 9m^3/min for 60 minutes, that frac interval would be billed at 18m^3/min for 60 minutes.

While some may choose to do otherwise, typically coupled simul-frac utilizes a single blender (equipment that mixes water, sand, and chemicals and pushes that slurry to the low-pressure-side of the frac pumps).

Decoupled Simul-frac: When N wells are simultaneously fractured and both the operations and contracts are decoupled, that operational strategy is called "decoupled simul-frac." This approach is effectively having two, entirely independent frac spreads operating on the same pad.

Decoupled Operationally: The N well-stages being simultaneously fractured need nothing in common. Stages can be of entirely different designs, pumps-on/off times, flow rates, and/or slurry concentrations.

Decoupled Contractually: When N well-stages are simultaneously fractured, they are billed by the operator as separate frac intervals. The N well-stages do not share pumping durations and pressures and have independent flow rates. E.g., if two well-stages are decoupled simul-frac'ed, each at 9m^3/min for 60 minutes, the operator would be billed for 9m^3/min for 120 minutes (two frac intervals, each at 9m^3/min for 60 minutes).

While not always required, often N-well decoupled simul-frac includes having N blenders.

Some operators and service providers appear to operate using decoupled operations and coupled contracts. This was not considered in this study.

P Wireline Spreads: The term "wireline spread" refers generally to all equipment and personnel required to perform plug-and-perf activities: the wireline truck, pumpdown pumps and manifolds, crane, etc. If there are P wireline spreads, that means there is enough equipment and personnel onsite to perform plug-and-perf activities simultaneously on P wells (e.g., likely P cranes). Notice that, when doing N-well simul-frac, P does not need to equal N.

When P is greater than 1, the operation is assumed to always be "decoupled". I.e., the "spreads" can operate entirely independently. This decoupled wireline spread operation is independent of whether a simul-frac spread is operationally coupled or decoupled.

Treatment, Non-Treatment, Non-pumping: A typical stage's pumping duration consists of multiple phases. While these vary greatly, in general, there are three high-level periods.

1. a period of pumping water and chemicals (e.g., while breaking down the stage, prior to slurry)
2. a period of pumping water, chemicals, and proppant/sand ("slurry")
3. a final period of pumping water and chemicals (e.g., flushing the proppant/sand from casing into the formation).

The frac pumping time for the stage is the combination of all three periods. The term "treatment" will refer specifically to this middle period when proppant/sand is being pumped at surface. The pre-treatment and post-treatment periods are "non-treatment" durations. I.e., non-treatment is not synonymous with "non-pumping." Non-pumping time is all time on the pad when pumping is not happening on any well (i.e., a combination of all well-to-well transition times). Non-pumping time is synonymous with frac spread standby time.

The total pumping hours are a combination of all non-treatment and treatment pumping hours. For single-frac and coupled simul-frac scenarios, the frac phase cycle time is equal to the combination of all non-pumping and pumping hours. Decoupled simul-frac scenarios are not as straightforward due to how pumping time accumulates versus calendar time.

A well's total non-treatment water volume and pumping duration are nonlinearly related to stage count.

Analysis Approach

The analyses performed relied heavily on commercially available simulation software specialized in simulating the horizontal well completions process. The software includes physics-based models capable of predicting pumping pressures and flow rates under most circumstances, including tracking minimum flow rate per cluster so design requirements can be upheld while optimizing lateral designs. There are options to guide different scenarios with different pumping strategies.

Further, the software includes a discrete-event, completions-process simulator with optimal frac order optimizer scalable to the diverse, complex combinations of designs, well counts, and simul-frac scenarios. This ensures that cycle times are fairly considered amongst scenarios in an automated way. Also, all the detailed impacts of varying parameters such as stage length can be captured (e.g., by determining what is on the critical path when).

Finally, detailed contractual inputs are included so precise, accurate cost impacts can be predicted. Design inputs are generalized but representative of the area and will be directly displayed. Cost inputs and outputs will be displayed in relative-to-base and/or normalized format. E.g., example outputs will include completions cost relative to the base scenario and average lateral length completed per day (meter/day). Cost breakdowns will leave some larger cost categories to help anonymize cost structures. Cycle time normalizations not only help obfuscate operator data but also help compare across scenarios where stage lengths vary, somewhat adjusting the final completed lateral lengths due to rounding to an integer number of stages.

Most units will be displayed in Metric but, when not cumbersome, equivalent Imperial will be shown as well.

The first three scenarios will represent operations constrained on maximum frac spread flow rate (due to single blender limitations) and maximum sand consumed per day (due to sand delivery limitations). The later scenarios will significantly lift these constraints.

Scope and Assumptions

The following highlights some key facets of this paper's scenarios.

Plug-and-Perf & Dynamic Clusters Per Stage

While simul-frac operations are immensely relevant to single-point entry strategies, this paper will focus on limited-entry plug-and-perf strategies. In these circumstances, the tradeoffs are especially difficult to quantify.

Limited-entry plug-and-perf requires maintaining a minimum perforation friction pressure ("min perf friction") across the clusters. In practice, this is executed by planning for and monitoring a minimum flow rate per cluster (min m^3/min/cluster, bbl/min/cluster). While a coupled 2-well simul-frac may have a higher total flow rate for the frac interval, the per well rates are usually lower than the equivalent single-frac scenario, resulting in fewer clusters per stage in comparison to single-frac. For the same lateral length, varying stage lengths results in varying numbers of stages and, therefore, wireline runs, plugs, flushes, etc.

So, to make a fair comparison, the single-frac and simul-frac scenarios have their clusters per stage dynamically optimized across the lateral—adding clusters as the minimum flow rate per cluster can still be met [Eidson et al. (2025)]. All scenarios in this paper use a standard perforating charge, resulting average perforation diameter, and set minimum flow rate per cluster. It is possible to decrease the perforating charge size and increase the number of clusters per stage, but that was not included in this analysis.

Coupled 2- or 3-well Simul-Frac

There are many interesting advantages to decoupled simul-frac. However, to control the scope of this paper, the scenarios will be limited to coupled simul-frac operations with a single blender.

4-well-and-beyond simul-frac is not considered in this analysis.

1-3 Wireline Spreads

The number of wirelines spreads per scenario can vary. Wireline-spread-related costs are scaled with number of spreads (e.g., number of cranes). In the single-frac scenario, one wireline spread was found to be optimal (the slight increase in cycle time is outweighed by the cost savings of not having a 2nd wireline spread present). For most 2-well and 3-well simul-frac, two wireline spreads are used. One 3-well simul-frac scenario tests the what-if of having a 3rd wireline spread.

Other Pumping Considerations

To decrease chances of screen out when simul-frac'ing, some operators reduce their slurry concentrations and/or adjust chemical packages. For simplicity, adjustments were not considered in this study.

Simul-frac'ing, in comparison to single-frac'ing, can increase the pressure needed to extend fractures due to stress shadowing. To capture this impact, the targeted formation's (or "type curve region's") frac gradient, expected to be 21kPa/m (~0.93 psi/ft) for single-frac, is increased by about 10% for simul-frac scenarios.

Tier 4, Dual-Fuel Frac Spread

A dual-fuel frac spread was assumed. For all scenarios, a fixed substitution percentage of 75% was used.

Pumping Services Contract

Three other key assumptions of this analysis are based on the pumping services contract. The first relates to the incremental hourly cost charged by the pumping provider for higher flow rates (additional maximum HP) in the 2- and 3-well simul-frac scenarios. The simulation software can capture pumping services contracts whose $/hr charge varies based on the pumping pressure and/or, as relevant in this case, the pumping flow rate. For anonymity, only relative price increases with respect to the prior $/hr step are shared (Table 1).

Table 1—Incremental increase in active pumping services cost rate ($/hr) for various frac interval flow rates

m³/min:	6	8	10	12	14	16	18	20	22	24	26	28
bbl/min:	37.7	50.3	62.9	75.5	88.0	100.6	113.2	125.8	138.4	151.0	163.5	176.1
Incr. $/hr %	-	6.2%	5.8%	5.5%	7.2%	12.1%	6.3%	5.9%	12.0%	6.0%	6.0%	12.0%

No scenarios will be considered that have a maximum frac interval flow rate above the maximum documented in the contract (28m³/min). This is assumed to be the maximum-sized frac crew available (this paper's simulations estimate 28m³/min would require over 30 engines and pumps).

A second key contractual assumption is what flow rate from a scenario is used to select the $/hr from the contract table. In this study, the contract is configured to identify the peak hydraulic horsepower from all the pad's frac intervals. That frac interval's flow rate is used to determine the $/hr charged on every stage on the pad. I.e., all stages will have the same $/hr charge based on peak-HP-stage's flow rate. Because the commercial software scales the number of engines and pumps based on engine and pump inputs (e.g., nameplate power, efficiencies, etc.), this corresponds to the operator being charged based on the number of engines/pumps brought out to service the job requirements. This assumption has a significant impact on scenario results.

Thirdly, the frac contract also includes both day-rate and non-pumping/inactive/standby charges. The standby charge applies to all times the frac crew is not pumping. While far lower than the active pumping charges, the standby charge has a non-trivial impact on scenario differences.

Constrained, Optimized Flowrates

The base single-frac treatment flow rates and pressures are representative of historic operations in the area. Amongst the most sensitive assumptions for the scenarios is the achievable per-well (and, therefore, total frac interval) flow rate. The simulation software includes physics models and operational inputs to estimate hydraulic pressures and flow rates. Scenarios will be constructed ensuring the following.

- Constraints for that scenario are not violated (e.g., maximum sand per day).
- An optimal maximum flow rate is identified (given the frac contract charging the same $/hr for all stages based on the peak-HP-stage and the goal of optimizing clusters per stage based on minimum flow rate per cluster limits).

Individual Scenario Optimization

Each individual scenario has multiple optimizations performed so the scenario comparison can be "best versus best." Three optimizations are performed, each affecting the other: optimal per-well maximum flow rate, optimal number of clusters per stage [Eidson et al. (2025)], and optimal number of wireline spreads. Because there is often a discrepancy between which combination minimizes cost versus cycle time, minimizing cost will be prioritized. Usually, it was found that capping the flow rate after the final cluster per stage could be added was more optimal than continuing to let the rate increase.

Scenario Overviews

This study will investigate six key scenarios. The first is the baseline, single-frac scenario. The second and third are 2-well and 3-well simul-frac scenarios, respectively, constrained by a single blender (max 20m^3/min; 126 bbl/min) and current logistics capabilities (max 4,300t/day; 4,740T/day). Note: this paper uses "t" to indicate a Metric ton (1,000kg) and "T" to indicate an imperial ton (2,000lb).

The fourth and fifth scenarios are the same simul-frac scenarios constrained only by maximum frac spread size (max 28m^3/min), adding additional blender capacity and ignoring the sand delivery constraint. The sixth scenario is the same as the fifth, but a 3rd wireline spread is added. While there are other important factors, the scenarios are named based on the number of wells being simultaneously fractured and the maximum frac interval flow rate constraint. To clarify, the maximum frac interval flow rate constraint does not mean that scenario ever had a frac interval flow rate that hit that constraint. The final scenario name appends "3WL" at the end because it is the one scenario where 3 Wireline Spreads are tested.

Table 2—Summary of key scenario assumptions and constraints (t = Metric ton; T = Imperial Ton)

Scenario #	# Wells Simul-Frac'ed	# Wireline Spreads	Blender Constraint		Frac Spread Constraint		Sand Delivery Constraint		Scenario Name
			m³/min	bbl/min	m³/min	bbl/min	t/day	T/day	
1	**1**	1	**20**	**126**	28	176	4,300	4,232	**Base Single-Frac**
2	**2**	2	**20**	**126**	28	176	4,300	4,232	**2-Well Simul-Frac, 20m³/min**
3	**3**	2	**20**	**126**	28	176	4,300	4,232	**3-Well Simul-Frac, 20m³/min**
4	**2**	2	40	252	**28**	**176**	-	-	**2-Well Simul-Frac, 28m³/min**
5	**3**	2	40	252	**28**	**176**	-	-	**3-Well Simul-Frac, 28m³/min**
6	**3**	**3**	40	252	**28**	**176**	-	-	**3-Well Simul-Frac, 28m³/min, 3WL**

Table 3 (Metric) and Table 4 (Imperial) provide an "input summary" for the scenarios. Several of these values (e.g., stage length) are really derived from more fundamental inputs (e.g., cluster spacing and clusters per stage). Others are set more granularly than the well-level, so a per-well average is taken (e.g., avg clusters per stage). Many of the inputs were based on optimization performed on that single scenario (e.g., avg clusters per stage and max working pumping flow rate). Notice the optimal value for max working flowrate was often found to be below the scenarios' theoretical maximum. Many of the parameters are the same across all scenarios.

The individual scenario sections will document more input details, especially regarding the inter-scenario optimizations performed to select some of the inputs.

Table 3—Summary of key scenario inputs (Metric)

Scenario Name	Target Lateral Length (m)	Sand Loading (t/m)	Avg Slurry Concen. (Treatment) Per Stage (kg/m³)	Max Working Pumping Pressure (MPa)	Avg Cluster Spacing (m)	Max Working Pumping Flow Rate (m³/min) per well	Max Working Frac Spread Flow Rate (m³/min)	Avg Clusters Per Stage	Avg Stage Length (m)	Avg Number Completed Stages Per Well	Avg Lateral Length Per Well (m)
Base Single Frac	3250	2.5	250	64	10	12	12	6.17	61.7	53	3270
2-Well Simul-Frac, max 20m³/min	3250	2.5	250	64	10	9	18	5.64	56.38	58	3270
3-Well Simul-Frac, max 20m³/min	3250	2.5	250	64	10	6.65	19.95	4.00	40	81	3240
2-Well Simul-Frac, max 28m³/min	3250	2.5	250	64	10	10.5	21	5.84	58.39	56	3270
3-Well Simul-Frac, max 28m³/min,	3250	2.5	250	64	10	9	27	5.64	56.38	58	3270
3-Well Simul-Frac, max 28m³/min, 3WL	3250	2.5	250	64	10	9	27	5.64	56.38	58	3270

Table 4—Summary of key scenario inputs (Imperial)

Scenario Name	Target Lateral Length (ft)	Sand Loading (lb/ft)	Avg Slurry Concen. (Treatment) Per Stage (lb/gal)	Max Working Pumping Pressure (PSI)	Avg Cluster Spacing (ft)	Max Working Pumping Flow Rate (bbl/min)	Max Working Frac Spread Flow Rate (bbl/min)	Avg Clusters Per Stage	Avg Stage Length (ft)	Avg Number Completed Stages Per Well	Avg Lateral Length Per Well (ft)
Base Single Frac	10,663	1,680	2.09	9,280	32.8	75.5	151	6.17	202	53	10,728
2-Well Simul-Frac, max $20m^3$/min	10,663	1,680	2.09	9,280	32.8	56.6	113.2	5.64	185	58	10,728
3-Well Simul-Frac, max $20m^3$/min	10,663	1,680	2.09	9,280	32.8	41.8	83.6	4.00	131	81	10,630
2-Well Simul-Frac, max $28m^3$/min	10,663	1,680	2.09	9,280	32.8	66	132	5.84	192	56	10,728
3-Well Simul-Frac, max $28m^3$/min,	10,663	1,680	2.09	9,280	32.8	56.6	113.2	5.64	185	58	10,728
3-Well Simul-Frac, max $28m^3$/min, 3WL	10,663	1,680	2.09	9,280	32.8	56.6	113.2	5.64	185	58	10,728

Scenarios 1-3: Fairly Constrained

Base Single-Frac Scenario

A base single-frac scenario will be documented and used in comparison to all simul-frac scenarios. A 6-well pad with identical designs and target benches (i.e., type curve regions) was selected.

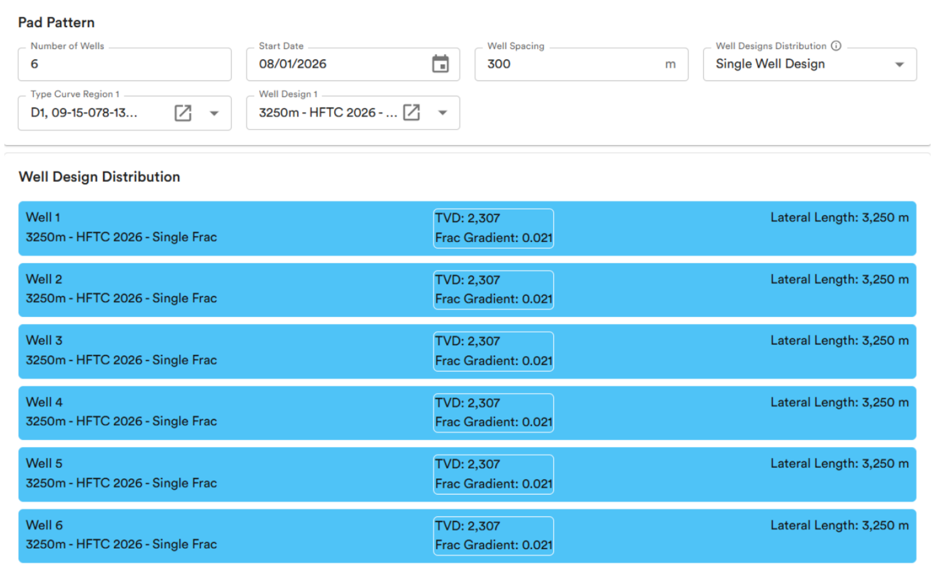

Figure 1—All scenarios assume a 6-well pad with common target bench (type curve region) and well design

Lateral lengths of approximately 3,250m (approx. 10,700ft) were used with 4.5″ Monobore casing.

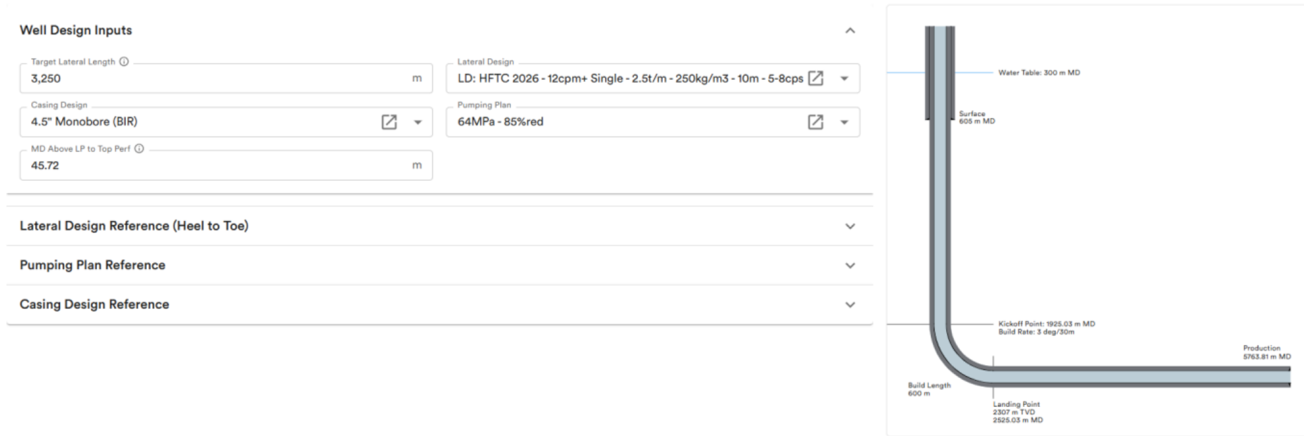

Figure 2—All scenarios target 3,250m laterals; lateral designs and pumping operational plans will vary between scenarios

The lateral length for all scenarios is approximately 3,250m because an integer number of stages is always rounded to. The rounded values varied from 3,240m to 3,270m. This underlines why comparisons are primarily between metrics normalized by lateral length (e.g., $/m and m/day).

The fundamental stage design for these wells is shown in Fig. 3, with the displayed clusters per stage being specific to the heel-most stage for the single-frac case. The average water loading ends up being in the 11.5-12 m^3/m (22-23bbl/ft) range (the varying number of stages in a lateral affects scenarios' average water loading per well due to varying number of, e.g., flushes).

Figure 3—Heel-most stage design of base single-frac scenario; some deeper stages will have fewer clusters

A critical input is the "Minimum Flow Rate Per Cluster." This value is used, in combination with the simulated pad's estimates of achievable stage flow rates, to determine approximate locations throughout the lateral where clusters can be added, or, if looking from the heel, where clusters need to be dropped. The pumping predictions are based on physics and operator direction, e.g., the maximum working pumping pressures and flow rates and fluid system's friction reduction %). In all scenarios, the maximum working pumping pressure is set to 64MPa. In the single-frac scenario, the flow rate was assumed unconstrained. Physics takes it from there.

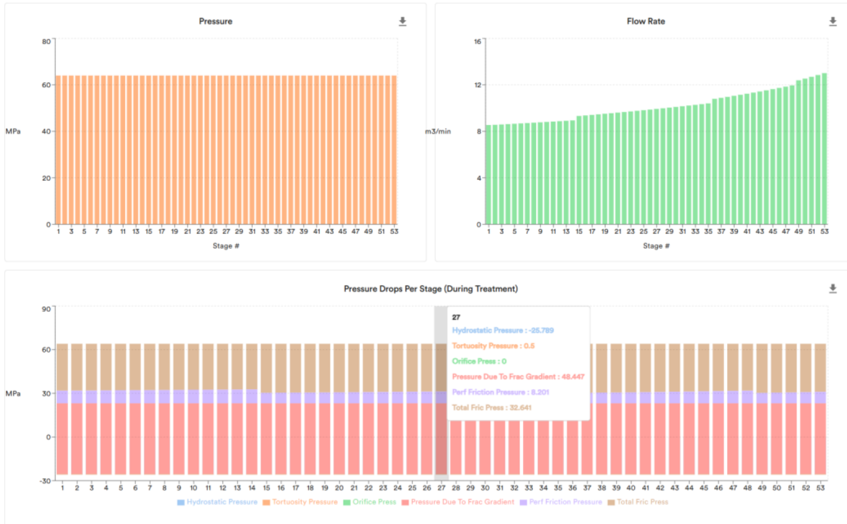

Figure 4—Single-Frac Scenario's treatment physics results based on 64MPa Max Working Pumping Pressure (same max used in all scenarios)

The heel-most stage is estimated to be able to hit 13 m^3/min (81.8 bbl/min). However, because of the pad-wide $/hr being picked based on that peak HP, and no additional clusters can be added to stages beyond 12m^3/min until 13.5m^3/min (due to the minimum 1.5m^3/min/cluster requirement), it turns out capping the rate at 12m^3/min (75.5 bbl/min) has slightly higher cycle time but slightly lower completions costs.

Combined with the minimum flow rate per cluster, the software estimates how many clusters are possible per stage (see full workflow in [Eidson et al. (2025)]). A few iterations are made until an optimal number of clusters for every stage is set. i.e., all "Possible Additional Clusters Over Design" are 0 (bottom-right plot in Fig. 5). Notice the relatively consistent average perf friction pressure (top-right plot in Fig. 5).

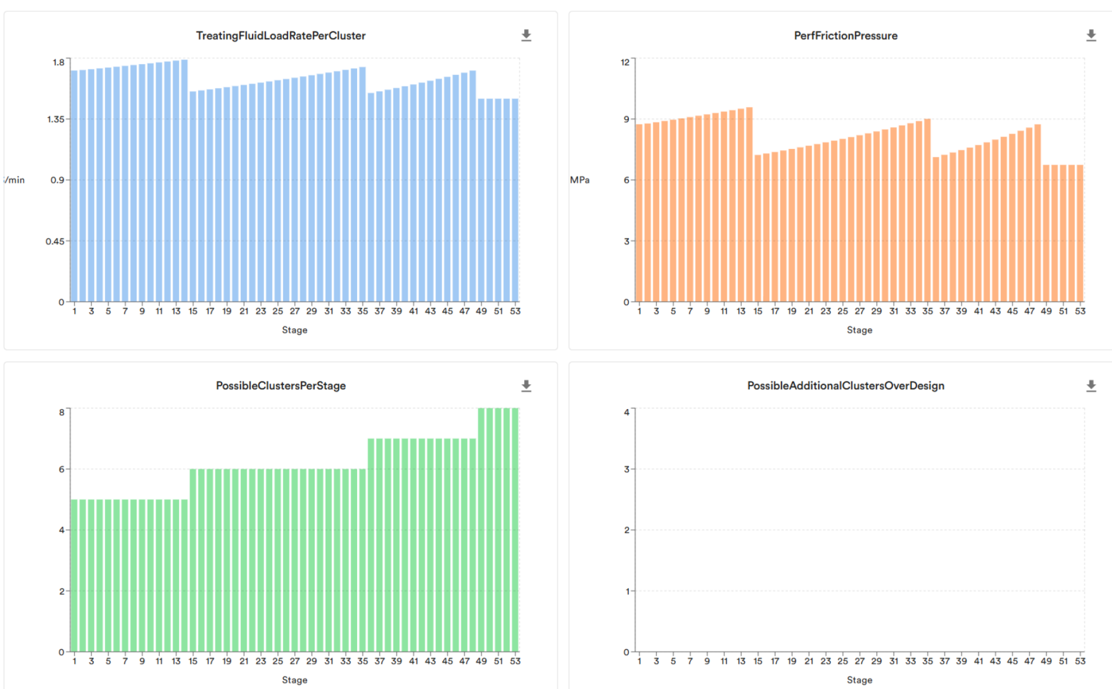

Figure 5—Plots showing optimized clusters per stage, based on minimum flow rate per cluster, for base single-frac scenario

Optimizing the base single-frac case results in the lateral design shown in Fig. 6. The stage design varies across the lateral, but only clusters per stage is changed. In this view, the lateral design's "top" stage design (8 clusters per stage) is for the heel-most stage. After a specified number of stages, the stage design is changed to fewer clusters per stage. The result is longer stages at shallower depths in the well. The toe-most stages have 5 clusters per stage.

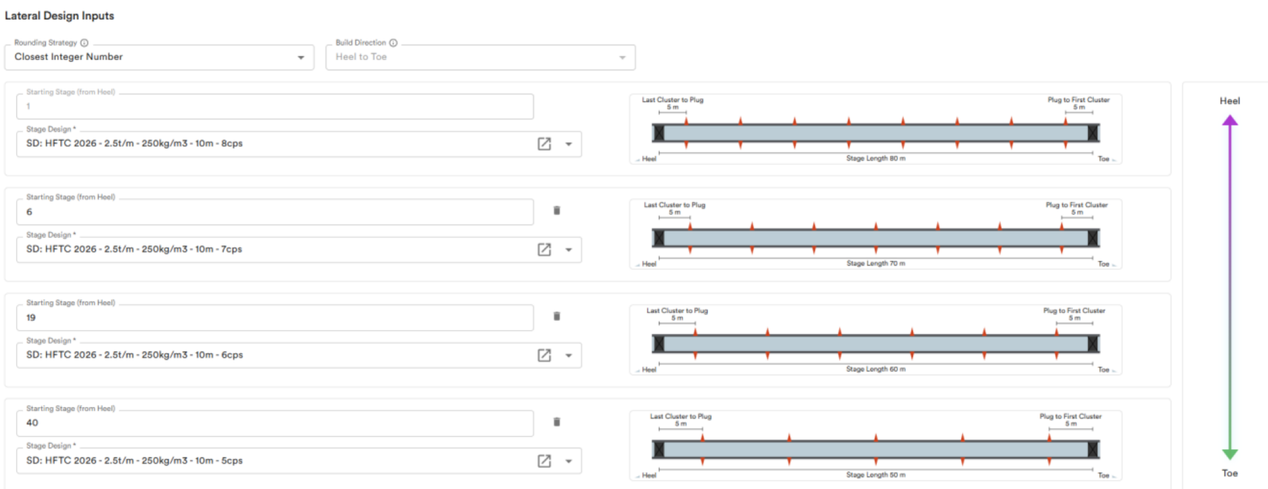

Figure 6—Base single-frac scenario's lateral design (showing where clusters are dropped as deeper in the lateral)

The result is 53 stages with an average stage length of 61.7m (202.4ft) and an average of 6.17 clusters per stage.

This optimization is necessary to fairly compare single-frac to the simul-frac scenarios. Otherwise, the increased per-well flow rate is not being "taken advantage of." For example, optimizing the clusters per stage, in comparison to the same scenario that using a static 5 clusters per stage throughout the entire lateral, **reduces the completions costs by almost 6% and reduces frac-phase cycle time by almost 8%**, savings comparable with previous work documented in this area [Eidson et al. (2025)].

The software performs a single-frac, inter-pad process simulation, estimating an optimal frac order, so Frac Phase cycle times can be accurately predicted.

Figure 7—Single-frac scenario's inter-pad Gantt chart

Non-frac phase cycle times (e.g., Prep, Mill-Out, etc.), are estimated far more simply through a combination of per pad, per well, per 1,000-lateral-meters, and per stage. The inputs shown in Table 5 assume two coil tubing units working in parallel. Because of varying estimating drillout times based on number of stages, these are relatively important inputs in comparing these scenarios.

Table 5—Inputs for non-frac completions phases

	Preparation	Mill Outs	Snubbing	Testing	Demob
days/pad	3	2	0	0	0
days/well	1	0.25	0.5	2	1.5
hrs/1,000m	0	0	0	0	0
minutes/stage	0	18.5	0	0	0

For the single-frac scenario, this results in the following cycle time estimates for the 6-well pad.

	Preparation	Frac Phase	Mill Outs	Snubbing	Testing	Demob
Days/pad	9.00	20.90	7.60	3.00	12.00	9.00

The Frac Phase and Mill-Outs phases are the only ones whose cycle times vary between scenarios.

Normalized Frac Phase cycle times and All-Phase (Prep-to-Demob) cycle times (completed lateral length per day) are important KPI's to compare. The completions cost relative to this scenario will be the primary KPI on which scenarios are compared. I.e., inter-scenario optimization will choose the designs and operation that minimize cost if there is ever a trade-off with maximizing lateral length per day.

The breakdown of the base single-frac scenario's completions cost is shown in Fig. 8. The cost categories are by phase and cost unit. The percentage shows how much of the overall cost that category is responsible for. Some cost units are combined to ensure cost structure anonymity. E.g., $/sand and $/pumping-hour are combined into a "stimulation" category. Absolute costs will not be shared to keep all cost results obfuscated.

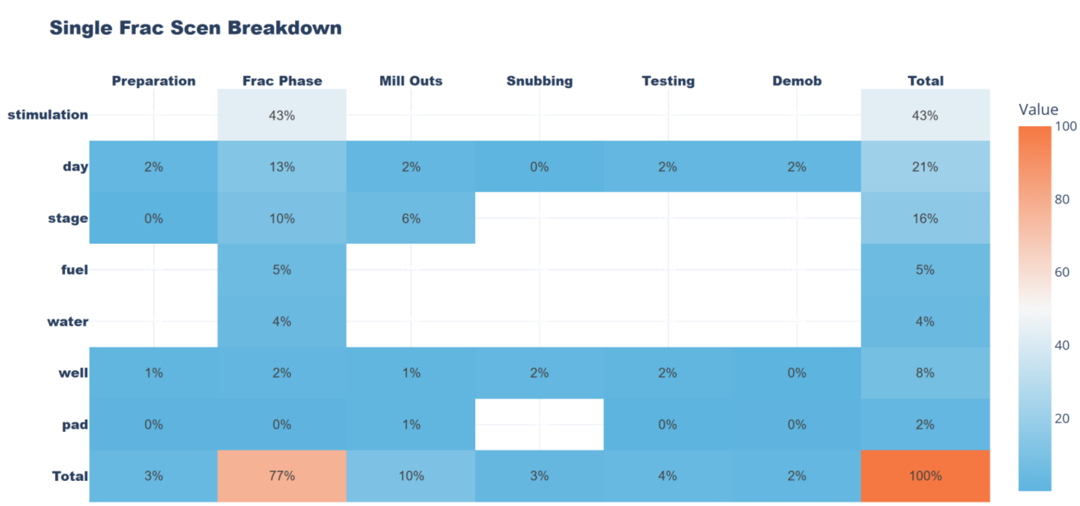

Figure 8—Breakdown of base single-frac scenario's completions cost by completions phase and cost unit

Unsurprisingly, most of the cost is from the Frac Phase. The largest cost component, stimulation, will have the sand-portion constant across scenarios. The smallest cost components ($/well and $/pad) will insert some small imprecisions in the comparisons due to these being normalized by potentially slightly different lateral lengths (due to rounding to an integer number of stages and scenarios having variable average clusters per stage). All other cost units have the potential to vary significantly amongst scenarios and will be the focus of the comparisons.

2-Well Simul-Frac, max 20m³/min

In converting the base single-frac scenario to a 2-well simul-frac scenario, the simulation needs a 2 Wireline Spread selected and its Frac Spread's Operational Configuration inputs adjusted as shown in Fig. 9.

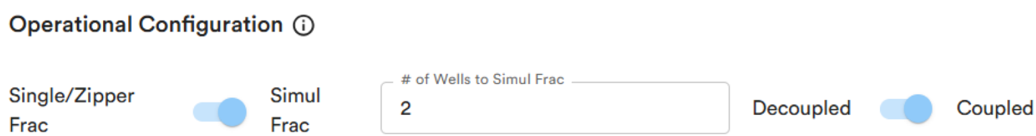

Figure 9—Configuring a Frac Spread for 2-well, coupled simul-frac

The simulation software determines an optimal frac order given the well and stage designs and operational configuration.

Figure 10—2-Well Simul-Frac, max 20m³/min scenario's inter-pad Gantt chart (no added swap time)

If no other inputs are changed, however, the simulation will still target the same max working pumping pressure and flow rates, add however many engines and pumps required, and ignore any other possible constraints. A later scenario will explore more unconstrained circumstances, but Scenarios 2 and 3 were developed around known constraints. Running with a single blender limits the total frac interval flow rate to 20m³/min. It took two iterations to determine that a maximum per-well working flow rate of 9m³/min (56.6 bbl/min), such that total frac spread rate is 18m³/min (113.2bbl/min), with accompanying optimized clusters/stage, minimized completions cost. Twenty-one engines and pumps are estimated to be needed. The final optimized well had 58 stages with an average stage length of 56.4m and 5.64 clusters per stage.

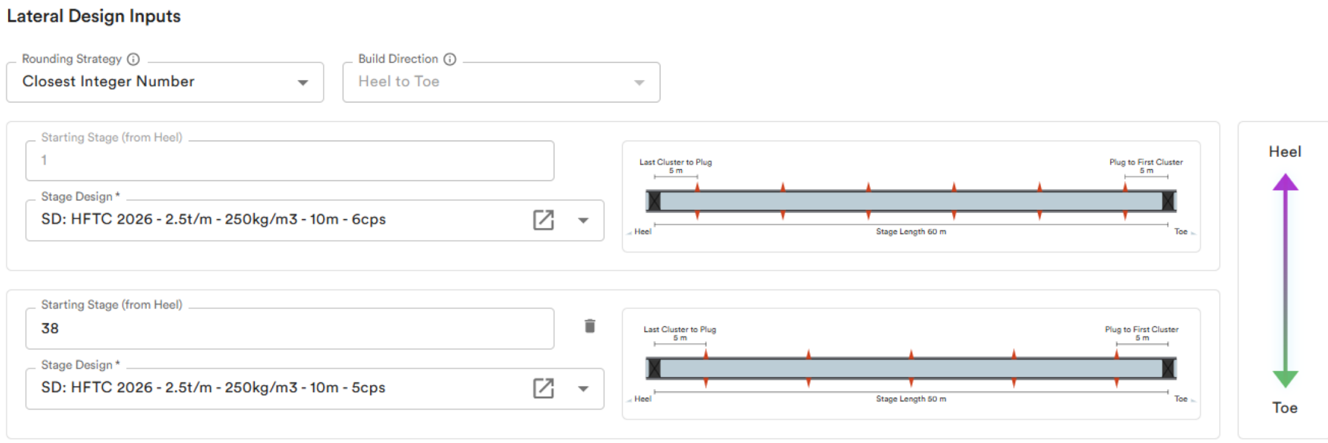

Figure 11—2-Well Simul-Frac, max 20m³/min scenario's optimized lateral design

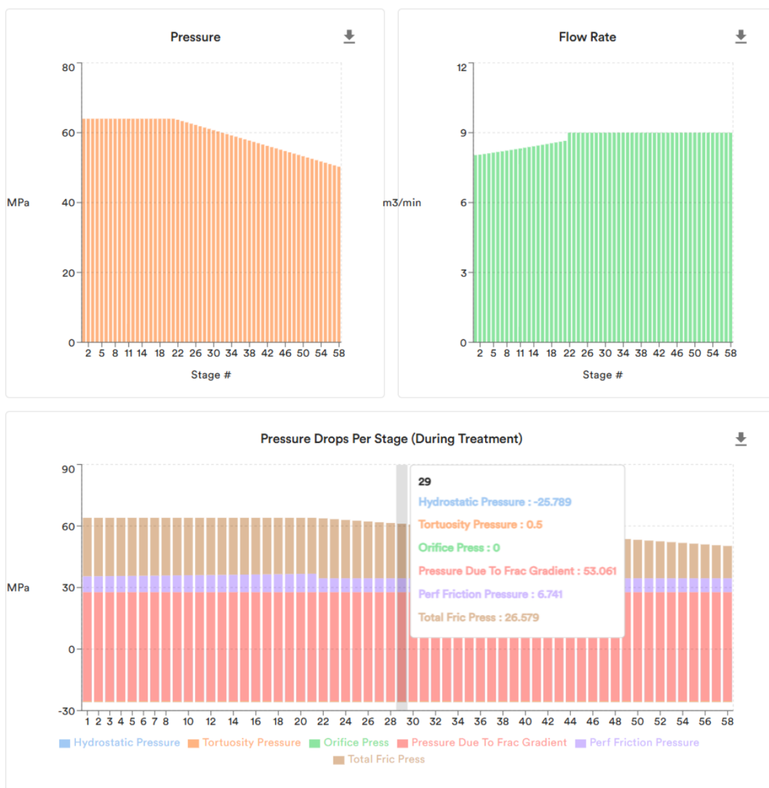

Figure 12—2-Well Simul-Frac, max 20m³/min scenario's estimated treatment pressures and flow rates

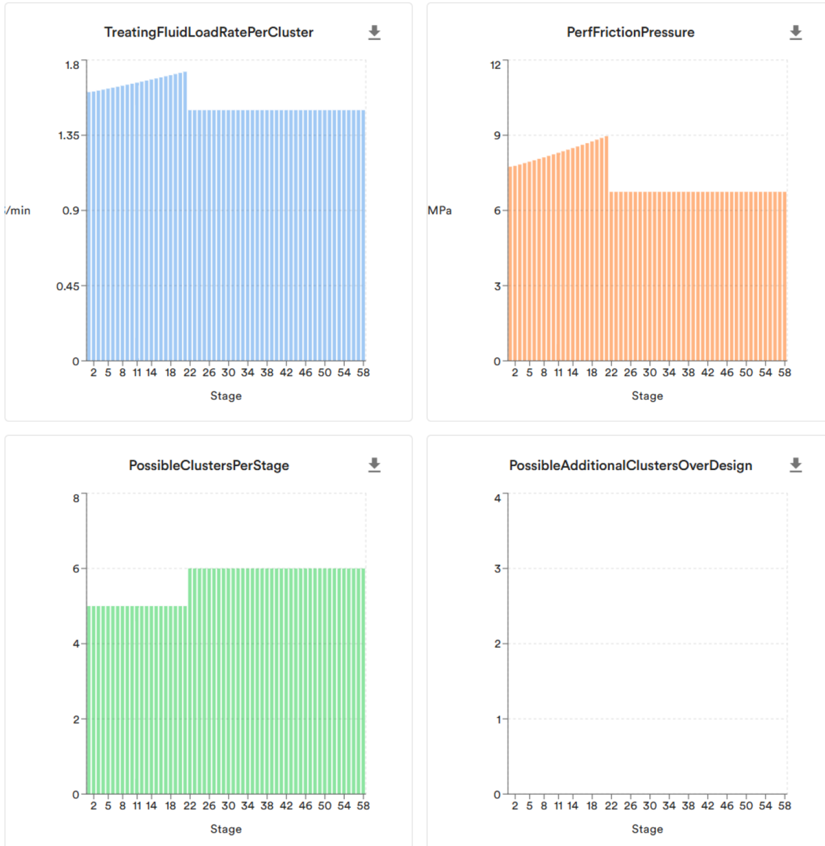

Figure 13—Demonstration of optimal clusters per stage selection for 2-Well Simul-Frac, max 20m³/min scenario

However, with no other changes, the operations slightly exceeded the maximum sand per day constraint (4,300t/day).

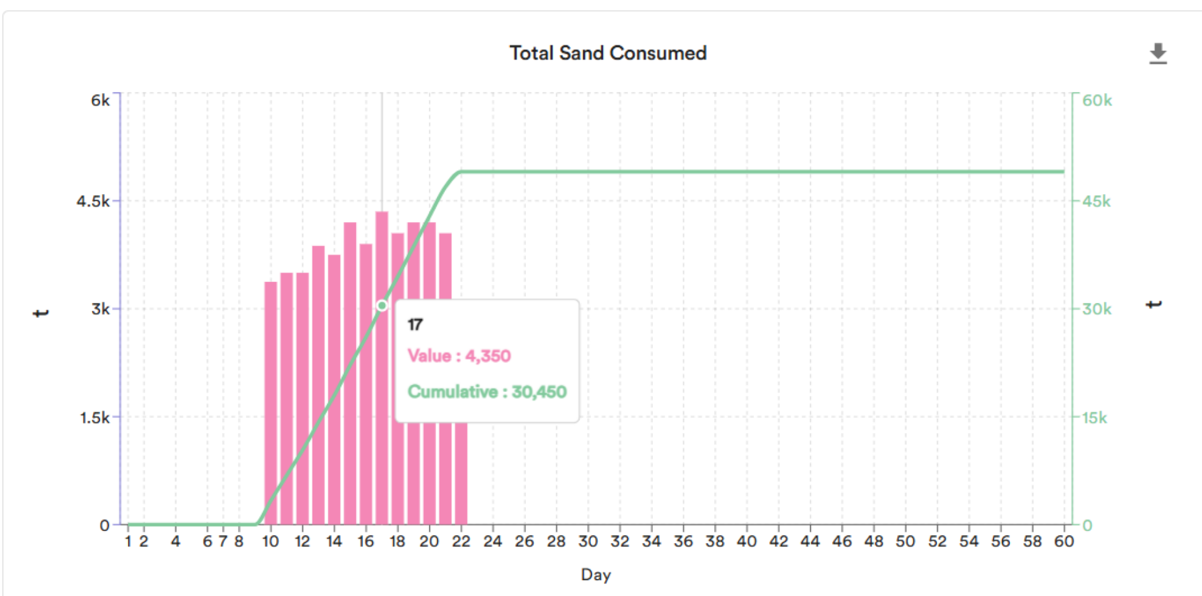

Figure 14—Sand per day for 2-Well Simul-Frac, max 20m³/min with standard swap times (exceeding 4,300t/day constraint)

The simulation platform currently allows users to run any what-if, including with respect to logistics. So, the Max Working Flow Rate input could be incrementally reduced while monitoring the simulations sand per day consumption until it is under the required limit. However, this solution would require dropping clusters per stage. Instead, for this scenario, additional swap time was added to slightly slow down operations (increasing average swap time from about 16 to 19 minutes). Whether this additional swap time is related to wireline, frac, or something else is considered inconsequential to this study. This change was sufficient to bring the max sand consumed per day to 4,200t/day. The increase in swap time increases costs due to increased cycle time and standby time, but it is still more economical than dropping flow rate and clusters per stage.

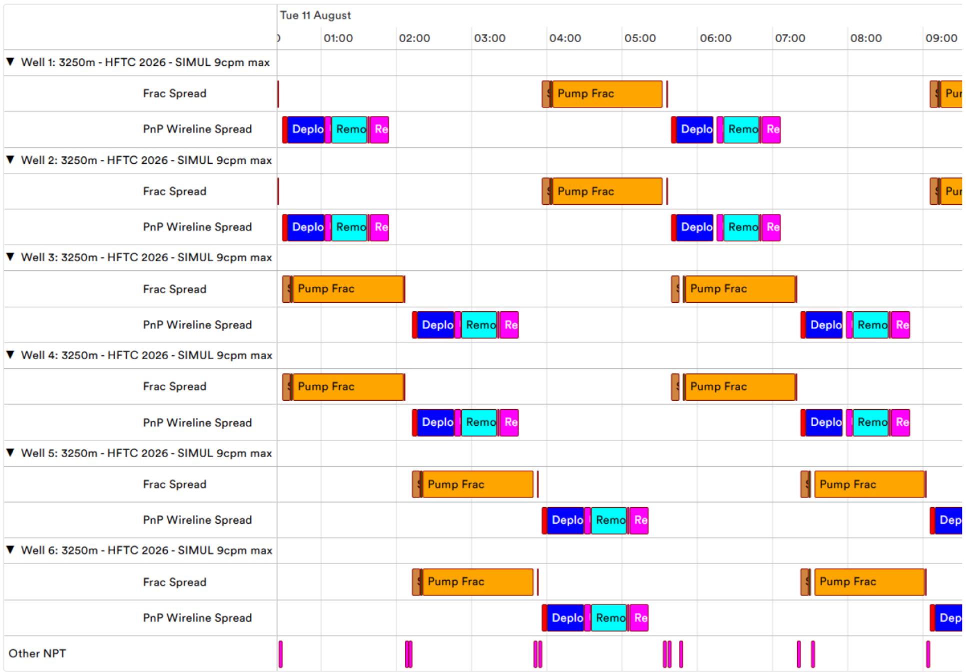

Figure 15—2-Well Simul-Frac, max 20m³/day inter-pad Gantt chart with additional swap time added

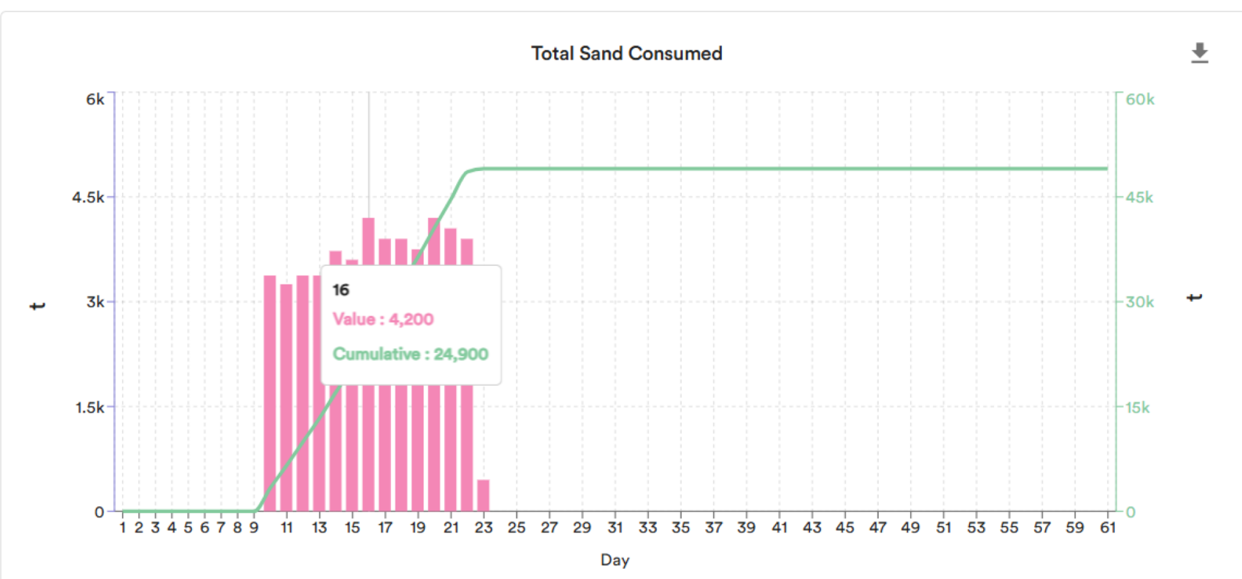

Figure 16—2-Well Simul-Frac, max 20m³/day sand per day after additional swap time added

Table 6 (Metric) and Table 7 (Imperial) are quick summaries of the design input differences between the two scenarios thus far. This includes quantities that are "almost" inputs—values immediately derived from inputs (e.g., stage length and stages per well are immediately derived from cluster spacing, clusters per stage, and target lateral length).

Table 6—Input summary of first two scenarios (Metric)

Scenario Name	Target Lateral Length (m)	Sand Loading (t/m)	Avg Slurry Concen. (Treatment) Per Stage (kg/m³)	Max Working Pumping Pressure (MPa)	Avg Cluster Spacing (m)	Max Working Pumping Flow Rate (m³/min)	Max Working Frac Spread Flow Rate (m³/min)	Avg Clusters Per Stage	Avg Stage Length (m)	Avg Number Completed Stages Per Well	Avg Lateral Length Per Well (m)
Base Single Frac	3250	2.5	250	64	10	12	12	6.17	61.7	53	3270
2-Well Simul-Frac, max 20m³/min	3250	2.5	250	64	10	9	18	5.64	56.38	58	3270

Table 7—Input summary of first two scenarios (Imperial)

Scenario Name	Target Lateral Length (ft)	Sand Loading (lb/ft)	Avg Slurry Concen. (Treatment) Per Stage (lb/gal)	Max Working Pumping Pressure (PSI)	Avg Cluster Spacing (ft)	Max Working Pumping Flow Rate (bbl/min)	Max Working Frac Spread Flow Rate (bbl/min)	Avg Clusters Per Stage	Avg Stage Length (ft)	Avg Number Completed Stages Per Well	Avg Lateral Length Per Well (ft)
Base Single Frac	10,663	1,680	2.09	9,280	32.8	75.5	151	6.17	202	53	10,728
2-Well Simul-Frac, max 20m³/min	10,663	1,680	2.09	9,280	32.8	56.6	113.2	5.64	185	58	10,728

Notice key input differences between the single-frac scenario and this 2-well simul-frac scenario.

- Reduced per-well Max Working Flow Rate (9m³/min versus 12m³/min) but greater max frac interval flow rate (18m³/min versus 12m³/min).
- Due to reduced per-well flow rates, reduced average clusters per stage and, therefore, reduced average stage length and increased stage count

Table 8 (Metric) and Table 9 (Imperial) show some key operational outputs between the two scenarios.

Table 8—Operational output comparison between first two scenarios (Metric)

Scenario Name	Avg Frac Water Per Unit Length (m³/m)	Avg Stage Pumping Pressure (Treatment) (MPa)	Avg Stage Pumping Flowrate (Treatment) (m³/min)	Peak Output Hydraulic Power (HP)	# Frac Engines & Pumps	Equiv. Pumping Time Per Unit Length (min/m)	Avg. Time Between Frac (min)	Avg Lat Length Per Day (Frac Phase) (m/day)	Avg Lat Length Per Day (All Phase) (m/day)
Base Single Frac	11.68	63.6	10.12	17,100	14	1.32	12.9	937	319
2-Well Simul-Frac, max 20m³/min	11.82	59.53	8.76	25,629	21	0.77	18.5	1,496	363

Table 9—Operational output comparison between first two scenarios (Imperial)

Scenario Name	Avg Frac Water Per Unit Length (bbl/ft)	Avg Stage Pumping Pressure (Treatment) (PSI)	Avg Stage Pumping Flowrate (Treatment) (bbl/min)	Peak Output Hydraulic Power (HP)	# Frac Engines & Pumps	Equiv. Pumping Time Per Unit Length (min/ft)	Avg. Time Between Frac (min)	Avg Lat Length Per Day (Frac Phase) (ft/day)	Avg Lat Length Per Day (All Phase) (ft/day)
Base Single Frac	22.4	9,224	63.6	17,100	14	0.40	12.9	3,075	1,046
2-Well Simul-Frac, max 20m³/min	22.7	8,634	55.1	25,629	21	0.24	18.5	4,907	1,190

Multiple differences are worth highlighting.

- For the same given sand loading, there is a slight increase in average water per unit length. This is due to additional stages requiring additional non-treatment pumping phases (e.g., stage breakdowns and flushes). While not especially significant in this study, in part to this study using a 4.5″ monobore casing with lower flush volumes, this is an often-overlooked component that reduces the total savings of simul-frac operations. When using liners or tapered strings, these flush volumes can have a significant impact on scenario results.
- 50% higher max frac interval flow rate did correspond to 50% more pumps and engines. Depending on scenario assumptions, this is not always the case. For example, with larger casings, the corresponding hydraulic horsepower for the same frac interval flow rate can be much lower for simul-frac in comparison to single-frac. So, if the number of pumps needed is dependent on horsepower requirement instead of flow rate, there can be a lower percentage increase in pumps than percentage increase in frac interval flow rate.
- The Equiv. Pumping Time Per Unit Length (min/m) incorporates whether multiple stages are frac'ed simultaneously. There is over a 40% drop from Base Single-Frac to 2-Well Simul-Frac, max 20m^3/min. One might expect it to be a 50% drop (when comparing 18m^3/min to 12m^3/min), but additional non-treatment pumping durations for the same fixed length reduces this drop.
- The average swap time (i.e., Avg Pumping Time Per Unit Length) increases by almost 50%. This is a result of frac'ing shorter stages and the additional swap time that was intentionally added to slow down operations to account for sand per day constraints.

The anticipated lateral length per frac-phase day **increases by almost 60%**. This metric is significant when considering Frac Spread schedule and efficiencies. The same metric considering all-phases (lateral length per all-phase day) increases by almost 14%. This metric is significant when considering well-days online. The Prep-to-Demob cycle time for this 6-well pad being reduced by 14% is **six wells online 8.5 days sooner**.

The contractual inputs are such that the cost estimates will automatically scale to the new simulation results, including having an additional Wireline Spread. However, for the simul-frac scenarios, some additional cost line items are required.

- Additional missile rentals (combination of fixed and spread rate)
- Additional supervision (spread rate)

The increased frac interval flow rate increases the per stage $/hr pumping service rate that is 28% higher than the base single-frac scenario. However, the total cost is split between the two stages being simul-frac'ed, ultimately reducing the active pumping costs per well by over 25%.

While absolute dollar comparisons would be far easier to understand, relative cost differences and breakdowns are shown to ensure cost structures are obfuscated. This scenario represents an overall **4.1% cost reduction** relative to the Base Single-Frac scenario. The breakdown of that 4.1% cost reduction is shown in Fig. 17. All the categories' percentages add up to 100% (i.e., they add up to 100% of the 4.1% cost difference). A positive percentage means 2-Well Simul-Frac is more expensive for that category. A negative percentage means 2-Well Simul-Frac is cheaper for that category. E.g., if the -4.1% represented -$100, the total Frac Phase cost would be $127 less expensive, and the total Mill Outs phase cost difference would be $21 more expensive.

Figure 17—Breakdown of cost difference between 2-Well Simul-Frac, max 20m^3/min and Base Single-Frac scenarios (negative indicates 2-Well Simul-Frac is cheaper)

Costs driven by stage count (i.e. pumpdown, perforating, plugs and millouts) end up being more expensive for 2-Well Simul-Frac (because of the decreased clusters per stage for the reduced per well injection rate). The Mill-Out duration increased due to the increased stage count, thereby also increasing cycle-time-driven costs for that phase. These cost increases are more than offset by cost reductions in stimulation (combination of sand and pumping hours) and Frac Phase cycle-time driven costs ($/day). The savings from each of these were almost five times greater than the increase in stage-count-related costs (68% ÷ 14% = 4.86). There were also non-trivial estimated fuel savings.

One fact obfuscated from this view is the $/day savings would be larger, but the standby costs are bucketed to the $/day cost category. Because this charge applies to all non-pumping time, this charge is higher for the 2-Well Simul-Frac, max 20m^3/min scenario in comparison to the Base Single-Frac scenario.

Despite a slight increase in Mill-Out costs due to longer durations from the higher number of stages, the 2-Well Simul-Frac, max 20m^3/min scenario predicts significant overall cycle time and cost savings.

3-Well Simul-Frac, max 20m^3/min

The same process used to create the rate-limited 2-Well Simul-Frac scenario was followed to create a 3-Well Simul-Frac scenario that is limited by the blender and the sand delivery to pad. The following key facets were determined.

- The maximum per-well working flow rate should be as high as possible given the combined 20m^3/min single-blender constraint. 6.65m^3/min (41.8bbl/min) was used as the Max Working Flow Rate per well.
- 6.65 m^3/min met the minimum requirement to use 4 clusters per stage.
- Only having two Wireline Spreads means, for 3-well simul-frac, a set of plug-and-perf activities will often be on the critical path. This slows the pace such that the standard operation was under the max sand per day constraint. Having a 3rd Wireline Spread was tested for this scenario, but the sand per day constraint was exceeded.

The following figures provide similar operational overviews as shown in the prior scenarios.

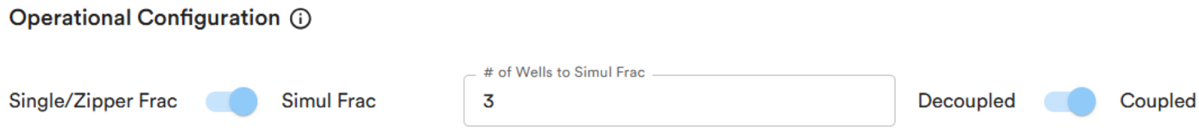

Figure 18—Frac Spread operational configuration for 3-well, coupled simul-frac

Figure 19—3-Well Simul-Frac, max 20m³/min scenario's inter-pad Gantt chart

Figure 20—3-Well Simul Frac, max 20m³/min scenario's estimated treatment physics

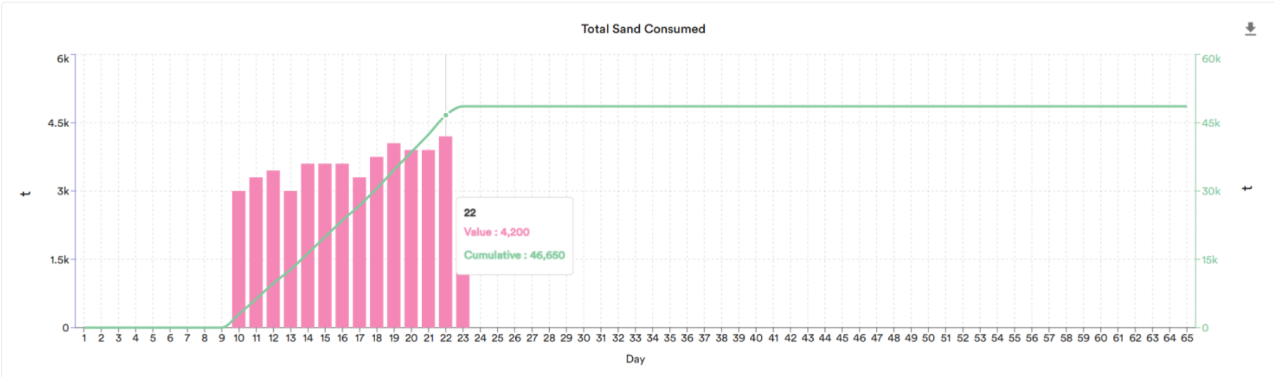

Figure 21—Sand consumed per day in 3-Well Simul Frac, max 20m³/min scenario

The input comparison is extended to this scenario and shown in Table 10 (Metric) and Table 11 (Imperial).

Table 10—Input comparison of first three scenarios (Metric)

Scenario Name	Target Lateral Length (m)	Sand Loading (t/m)	Avg Slurry Concen. (Treatment) Per Stage (kg/m³)	Max Working Pumping Pressure (MPa)	Avg Cluster Spacing (m)	Max Working Pumping Flow Rate (m³/min)	Max Working Frac Spread Flow Rate (m³/min)	Avg Clusters Per Stage	Avg Stage Length (m)	Avg Number Completed Stages Per Well	Avg Lateral Length Per Well (m)
Base Single Frac	3,250	2.5	250	64	10	12	12	6.17	61.7	53	3,270
2-Well Simul-Frac, max 20m³/min	3,250	2.5	250	64	10	9	18	5.64	56.38	58	3,270
3-Well Simul-Frac, max 20m³/min	3,250	2.5	250	64	10	6.65	19.95	4.00	40	81	3,240

Table 11—Input comparison of first three scenarios (Imperial)

Scenario Name	Target Lateral Length (ft)	Sand Loading (lb/ft)	Avg Slurry Concen. (Treatment) Per Stage (lb/gal)	Max Working Pumping Pressure (PSI)	Avg Cluster Spacing (ft)	Max Working Pumping Flow Rate (bbl/min)	Max Working Frac Spread Flow Rate (bbl/min)	Avg Clusters Per Stage	Avg Stage Length (ft)	Avg Number Completed Stages Per Well	Avg Lateral Length Per Well (ft)
Base Single Frac	10,663	1,680	2.09	9,280	32.8	75.5	151	6.17	202	53	10,728
2-Well Simul-Frac, max 20m³/min	10,663	1,680	2.09	9,280	32.8	56.6	113.2	5.64	185	58	10,728
3-Well Simul-Frac, max 20m³/min	10,663	1,680	2.09	9,280	32.8	41.8	83.6	4.00	131	81	10,630

The same observations made between Scenarios 1 and 2 are amplified here. In particular, the maximum clusters per stage drops to four and remains there throughout the entire lateral, as the limiting factor is not pipe friction but minimum rate per cluster. The drop from Scenario 1 to 2 was an 8.5% drop in clusters per stage. From Scenario 1 to 3 there is a 35% drop. This has a significant increase in stages per well. The result is an amplification of all the operational penalties highlighted in Scenario 2 (Table 12 and Table 13).

Table 12—Operational output comparison of first three scenarios (Metric)

Scenario Name	Avg Frac Water Per Unit Length (m³/m)	Avg Stage Pumping Pressure (Treatment) (MPa)	Avg Stage Pumping Flowrate (Treatment) (m³/min)	Peak Output Hydraulic Power (HP)	# Frac Engines & Pumps	Equiv Pumping Time Per Unit Length (min/m)	Avg. Time Between Frac (min)	Avg Lat Length Per Day (Frac Phase) (m/day)	Avg Lat Length Per Day (All Phase) (m/day)
Base Single Frac	11.68	63.6	10.12	17,100	14	1.32	12.9	937	319
2-Well Simul-Frac, max 20m³/min	11.82	59.53	8.76	25,629	21	0.77	18.5	1,496	363
3-Well Simul-Frac, max 20m³/min	12.53	50.14	6.65	24,799	20	0.72	32.5	1,441	346

Table 13—Operational output comparison of first three scenarios (Imperial)

Scenario Name	Avg Frac Water Per Unit Length (bbl/ft)	Avg Stage Pumping Pressure (Treatment) (PSI)	Avg Stage Pumping Flowrate (Treatment) (bbl/min)	Peak Output Hydraulic Power (HP)	# Frac Engines & Pumps	Equiv. Pumping Time Per Unit Length (min/ft)	Avg. Time Between Frac (min)	Avg Lat Length Per Day (Frac Phase) (ft/day)	Avg Lat Length Per Day (All Phase) (ft/day)
Base Single Frac	22.4	9,224	63.6	17,100	14	0.40	12.9	3,075	1,046
2-Well Simul-Frac, max 20m³/min	22.7	8,634	55.1	25,629	21	0.24	18.5	4,907	1,190
3-Well Simul-Frac, max 20m³/min	24.0	7,272	41.8	24,799	20	0.22	32.5	4,728	1,134

While operationally more efficient than the Base Single-Frac scenario, this 3-Well Simul-Frac, max 20m^3/min scenario is slower than its 2-well simul-frac equivalent.

Worse, this 3-well Simul-Frac scenario is estimated to be *more expensive* than both the 2-Well Simul-Frac, 20m^3/max and Base Single--Frac scenarios (**2.3% more expensive** than Base Single-Frac). The equivalent heatmap as Fig. 17 is provided in Fig. 22 comparing the 3-Well Simul-Frac, max 20m^3/min scenario to the Base Single-Frac scenario. It shows what percentage of the 2.3% cost difference each category makes up. Positive means 3-Well Simul-Frac is more expensive. Negative means 3-Well Simul-Frac is cheaper.

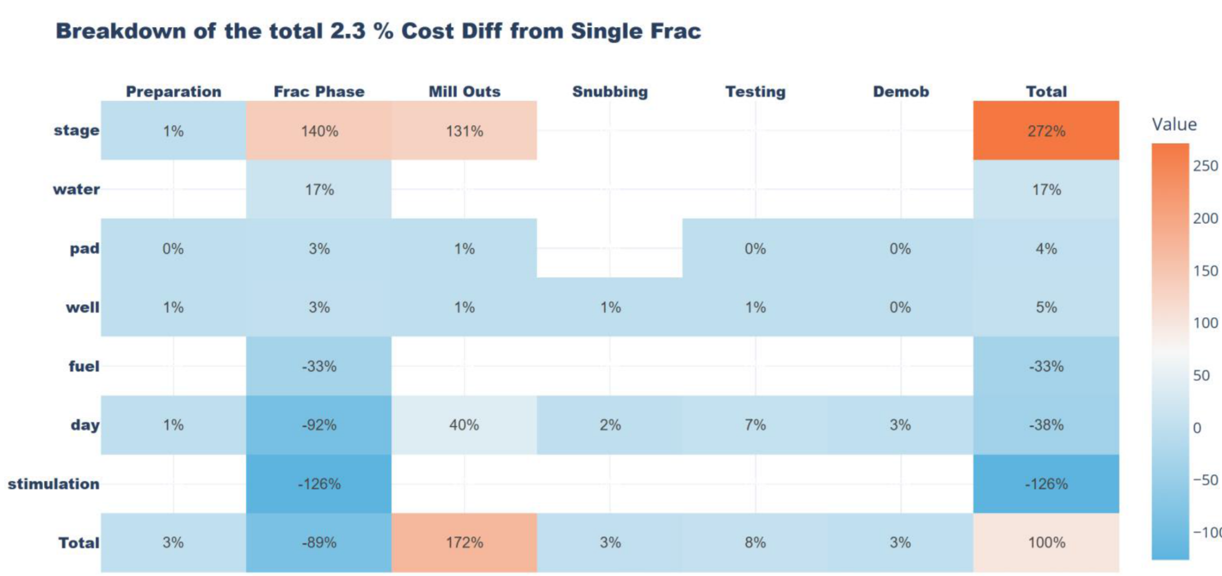

Figure 22—Breakdown of cost comparison between 3-Well Simul-Frac, max 20m³/min and Base Single-Frac scenarios (positive means 3-Well Simul-Frac is more expensive)

During the Frac Phase, increased stage-driven costs ($/stage + $/cluster) and some water-driven costs are offset with reductions in stimulation, fuel, and spread-rate costs (due to reduced Frac Phase cycle time). Like Scenario 2, the $/day savings of 3-Well Simul-Frac would be higher except that category includes the inactive/standby charges anytime pumping is not happening due to waiting on plug-and-perf activities. However, the increased stage count and resulting cycle time increase for the Mill-Out phase ultimately makes this scenario slightly more expensive than the prior two scenarios.

Intermission: Stage Length Sensitivities

While changing one or more aspects of these scenarios' specific circumstances could change the relative cost rankings, it is worth highlighting a fundamental driver in the tradeoff of simul-frac'ing in plug-and-perf operations. The number of stages in a given lateral is a nonlinear relationship with stage length. Therefore, gradually decreasing the average number of clusters per stage, with a given cluster spacing, can significantly increase a well's stage count and, therefore costs driven by stage count. Fig. 23 illustrates this using the three different lateral lengths.

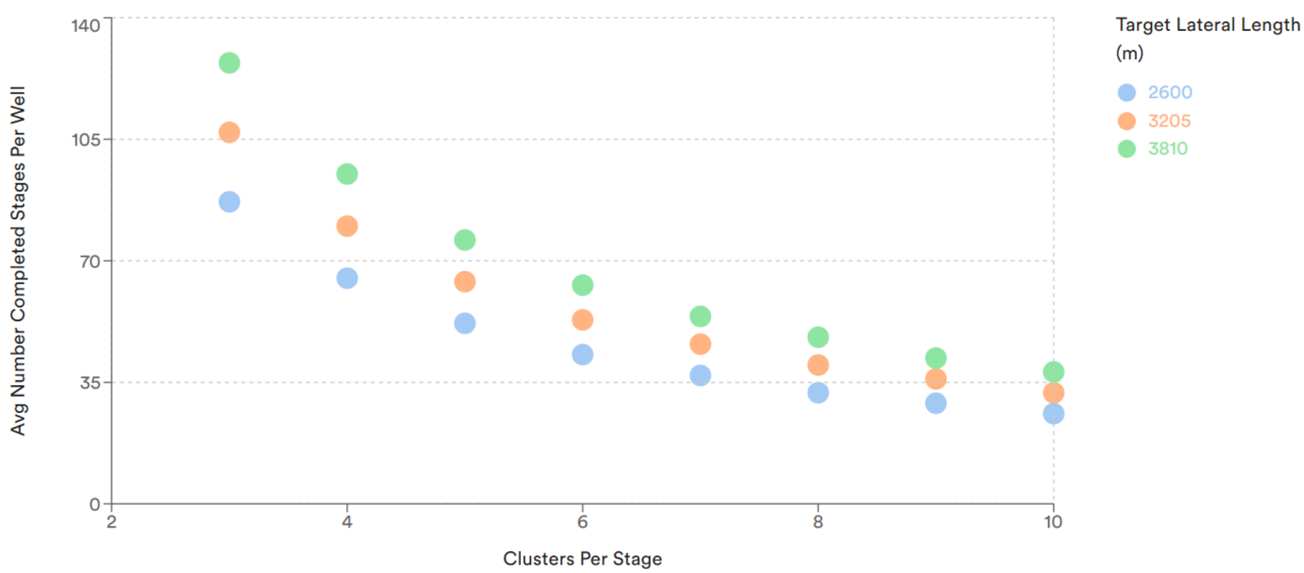

Figure 23—Stages per well decrease nonlinearly with increasing average clusters per stage

The increase in number of stages increases non-treatment water volumes, and, therefore, the average water loadings and non-treatment pumping durations (Fig. 24 and Fig. 25).

This nonlinear behavior is the primary reason the 3-Well Simul-Frac, max 20m^3/min, which could only support 4 clusters per stage, is so relatively uneconomical. I.e., the cost of moving from 6 to 5 clusters per stage is not as costly as moving from 5 to 4 clusters per stage. It also explains why the greater average clusters per stage in the Single Frac scenario is not a significant enough advantage to compensate for other increases in cost.

However, raising the flow rate constraints can increase the possible clusters per stage in one or more of the above scenarios and can change this optimal tradeoff. The remaining scenarios will do this. Having given detailed explanations of the driving factors in the results of the first three scenarios, the results of the last three scenarios can be made more succinctly.

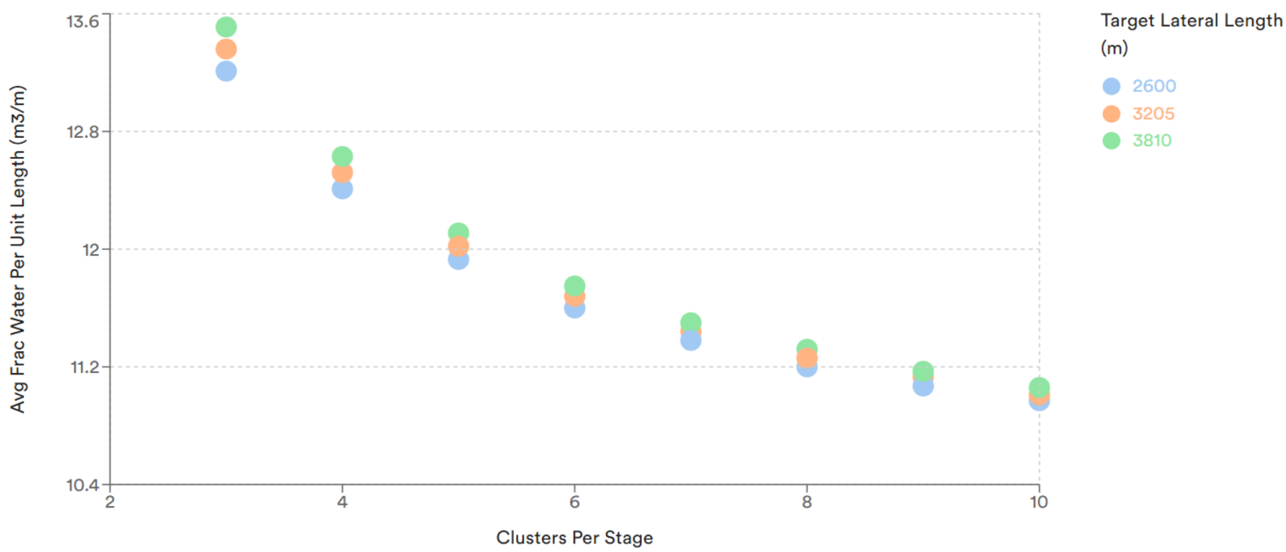

Figure 24—For a given pump schedule and fixed treatment slurry concentration, average water loading per well decreases nonlinearly with increasing average clusters per stage

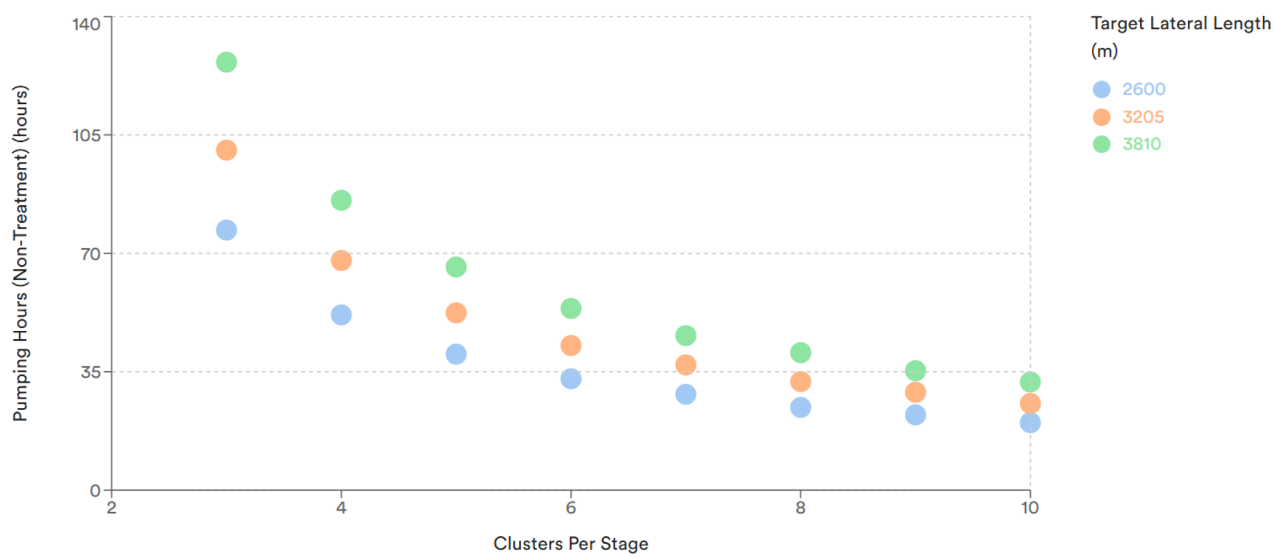

Figure 25—For a given pump schedule, non-treatment pumping hours decrease non-linearly with increase clusters per stage

Scenarios 4-6: Not-so Constrained

Scenarios 4-6 assume additional blender capacity is present such that up to 40m^3/min (~252bbl/min) could be pumped (the cost of an additional daily rental was added). A land constraint was kept in place, capping the number of engines and pumps such that the maximum frac interval rate would not be allowed to exceed 28m^3/min (~175bbl/min). The maximum sand per day limit was removed. Scenarios 4 and 5 continue with two Wireline Spreads, and Scenario 6 will assume a third Wireline Spread is present. Detailed input and operational output comparison will be done after the last scenario is introduced.

2-Well Simul-Frac, max 28m^3/min

Scenario 4 is another 2-well simul-frac scenario. The balance of active pumping services $/hr and optimizing clusters per stage resulted in choosing a Max Working Flow Rate of 10.5m^3/min (66bbl/min) per well (21m^3/min (132bbl/min) for the frac spread). Increasing to 13.5m^3/min (85bbl/min) per well (27m^3/min (170bbl/min) for the frac spread) did allow for some additional clusters on some of the heel-most stages and reduced cycle time, but the increased $/hr charged to all pad stages is more cost penalizing than capping the flow rate sooner and not adding more clusters (or engines/pumps). A different pumping services contract structure would likely lead to a different optimum.

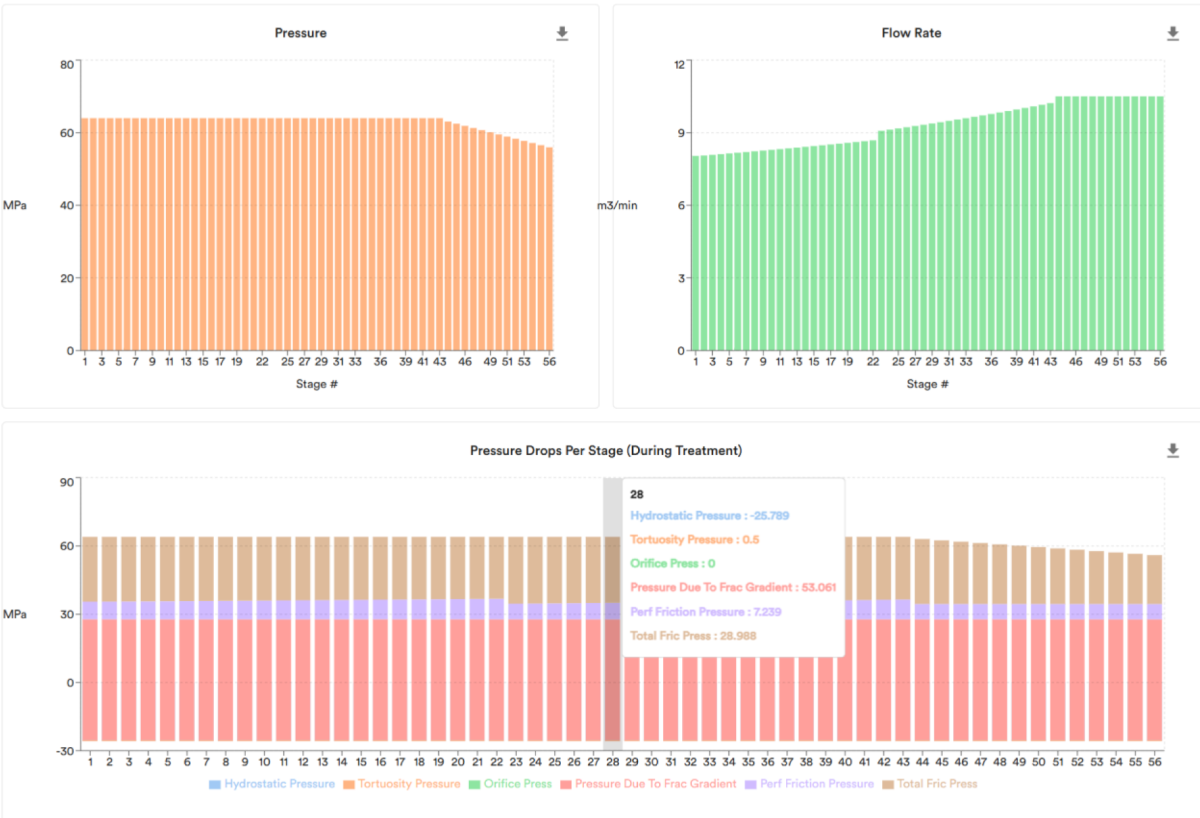

Figure 26—2-Well Simul-Frac, max 28m³/min scenario's treatment physics

This scenario would require almost 5,100t of sand per day.

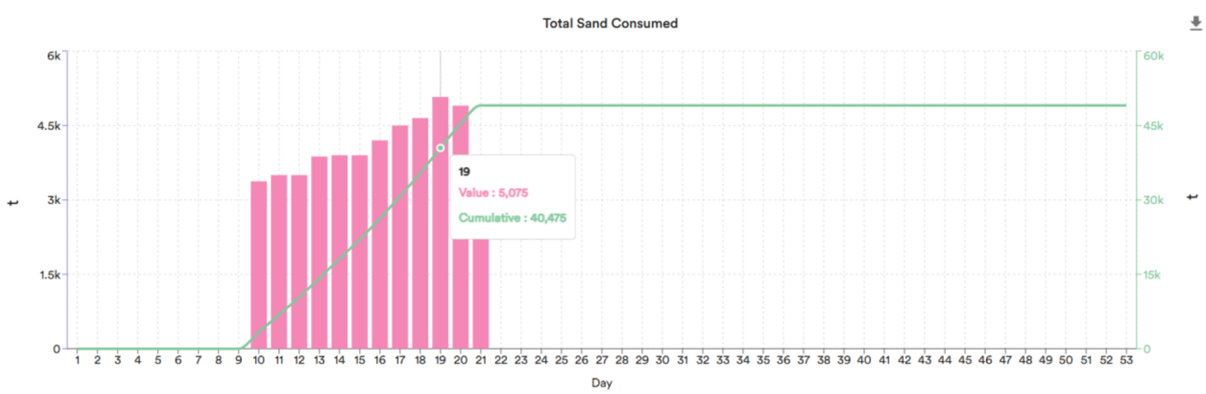

Figure 27—2-Well Simul-Frac, max 28m³/min scenario's estimated sand per day consumption

The cost savings in this scenario **(4.7% savings)** are even greater than the more constrained 2-Well Simul-Frac, max 20m³/min scenario (Scenario 2). The breakdown of the 4.7% savings is shown in Fig. 28. The stimulation ($/sand + $/pumping-hour) and spread rate ($/day) savings outweigh increases in stage and fuel costs.

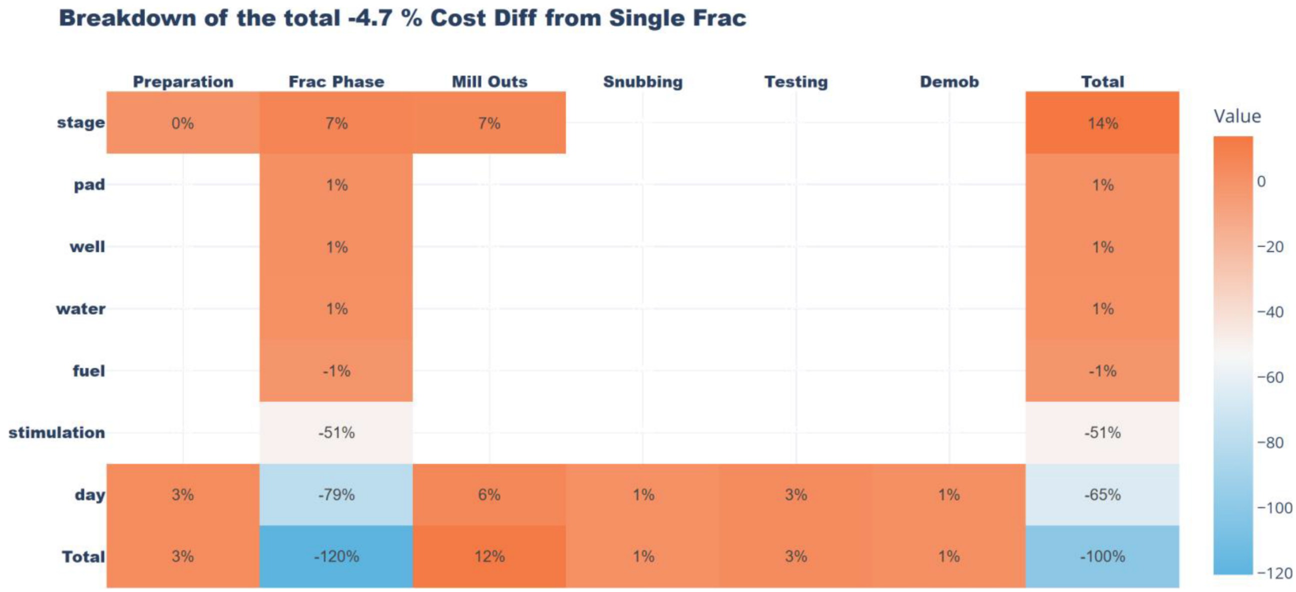

Figure 28—Breakdown of cost difference of 2-Well Simul-frac, max 28m³/min versus Single-Frac (negative is cost savings)

3-Well Simul-Frac, max 28m³/min

Moving the 3-Well Simul-Frac scenario to a maximum of 28m³/min enables it to move beyond the highly prohibitive 4 clusters/stage design (due to the minimum 1.5m³/min/cluster requirement). It was found a maximum per-well working flowrate of 9m³/min (56.6bbl/min) or 27m³/min (170bbl/min) for the frac spread was optimal for this scenario. This is the same per-well flow rate as the 2-Well Simul-Frac, max 20m³/min scenario (Scenario 2), so the result is the same optimal lateral design with same average clusters per stage.

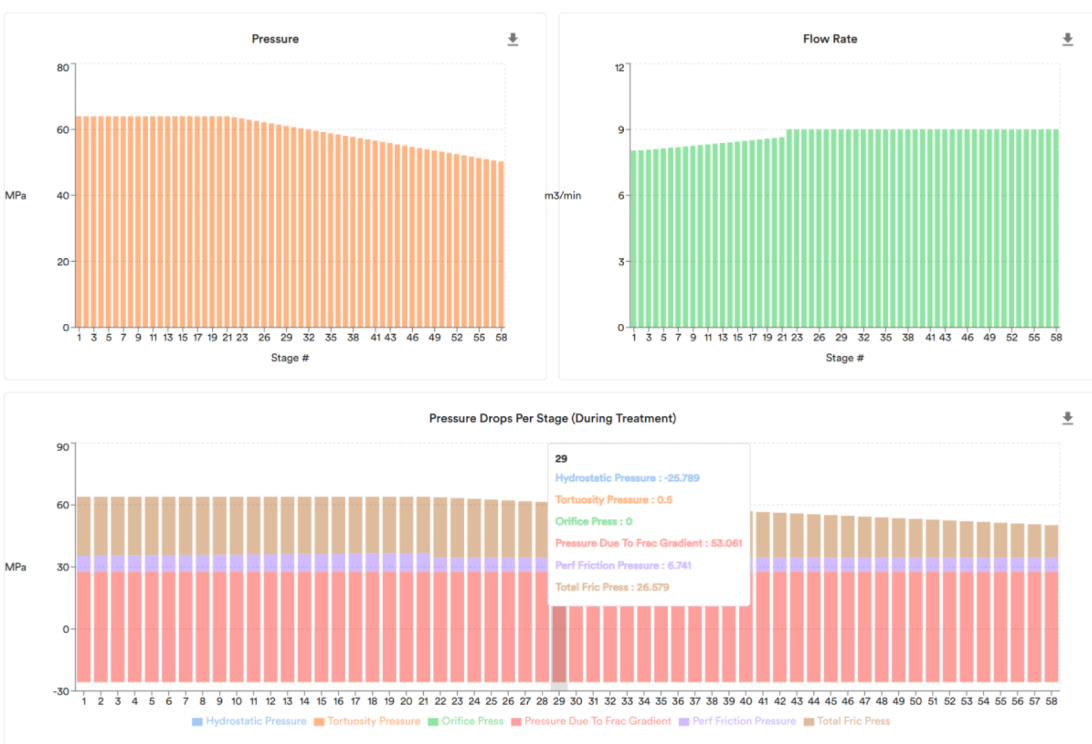

Figure 29—3-Well Simul-Frac, max 28m³/min scenario's treatment physics

Almost 5,900t of sand per day is estimated to be required.

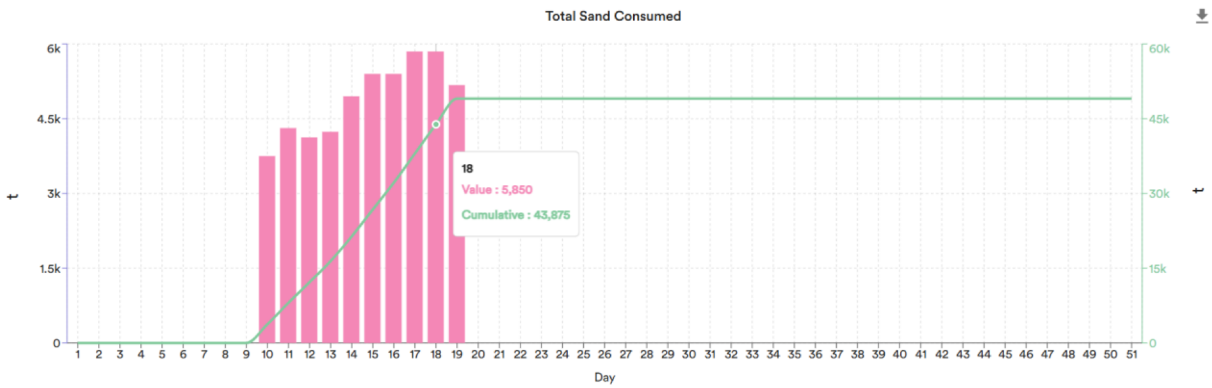

Figure 30—3-Well Simul-Frac, max 28m³/min scenario's estimated sand consumed per day

The same benefits of the 2-Well Simul-Frac, max 28m³/min scenario are amplified for the 3-well simul-frac equivalent, **saving 6.3%** in comparison to the Base Single-Frac scenario.

Figure 31—Breakdown of cost difference between 3-Well Simul-Frac, 28m³/min and Base Single Frac scenarios

As beneficial as the above scenario is, there is still a great deal of time spent waiting on plug-and-perf activities, increasing both spread-rate and standby frac services costs.

3-Well Simul-Frac, max 28m³/min, 3WL

The final scenario explores the potential value if a third Wireline Spread is added to the operations. Site surface constraints may have to be evaluated to ensure the additional equipment will safely fit on location, this analysis explores the potential value if one could. The rental rates increase to capture the additional equipment and personnel of a third wireline spread. All other aspects of this scenario were identical to Scenario 5.

The 3rd wireline fully removes the plug-and-perf activities from the critical path (Fig. 32).

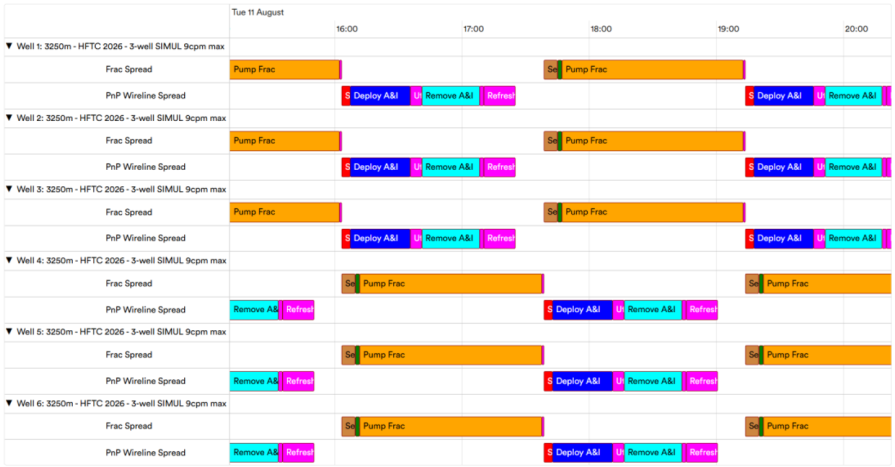

Figure 32—3-Well Simul-Frac, max 28m³/min, 3WL scenario's inter-pad Gantt chart

The peak daily consumption of sand is estimated to be 6,300t.

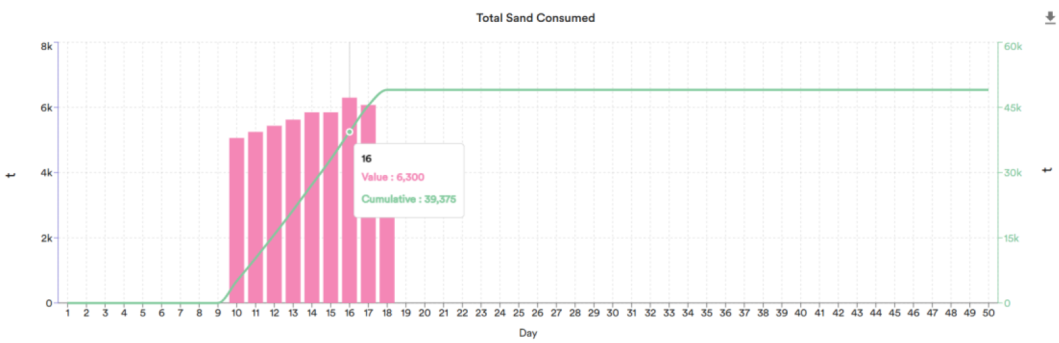

Figure 33—3-Well Simul-Frac, max 28m³/min,3WL scenario's estimated sand consumed per day

The benefits of the previous 3-Well Simul-Frac, 28m³/min with only two wireline spreads are further amplified. The **cost is reduced by 7%** in comparison to the Base Single-Frac scenario.

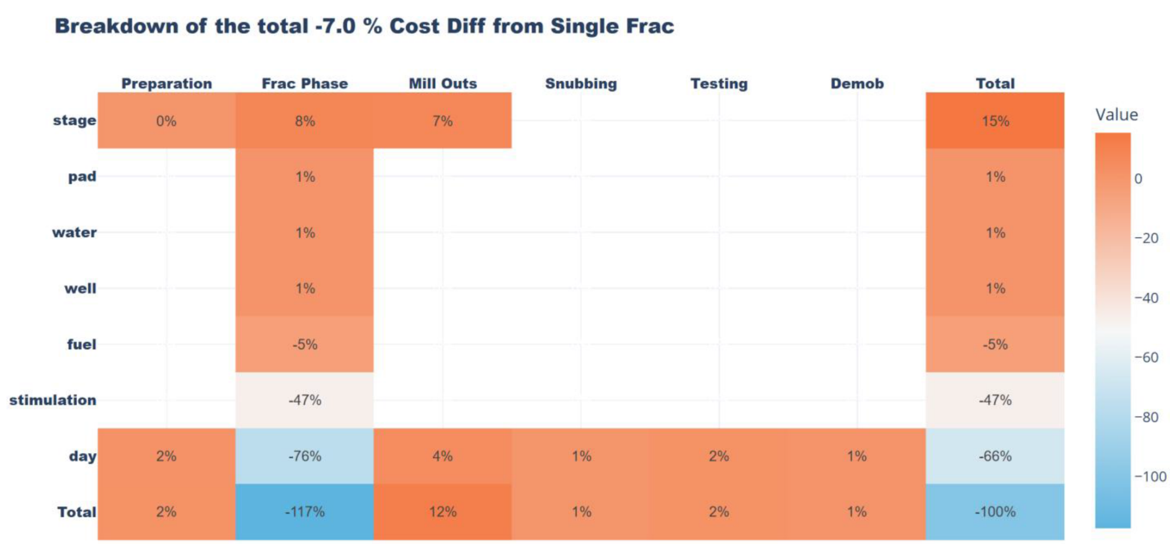

Figure 34—Breakdown of cost difference between 3-Well Simul-Frac, 28m³/min, 3WL and Base Single Frac scenarios

Scenario Summaries

Table 14 (Metric) and Table 15 (Imperial) provide a summary of the key design inputs for all six scenarios.

Table 14—Summary of key design inputs for all scenarios (Metric)

Scenario Name	Target Lateral Length (m)	Sand Loading (t/m)	Avg Slurry Concen. (Treatment) Per Stage (kg/m³)	Max Working Pumping Pressure (MPa)	Avg Cluster Spacing (m)	Max Working Pumping Flow Rate (m³/min)	Max Working Frac Spread Flow Rate (m³/min)	Avg Clusters Per Stage	Avg Stage Length (m)	Avg Number Completed Stages Per Well	Avg Lateral Length Per Well (m)
Base Single Frac	3250	2.5	250	64	10	12	12	6.17	61.7	53	3270
2-Well Simul-Frac, max 20m³/min	3250	2.5	250	64	10	9	18	5.64	56.38	58	3270
3-Well Simul-Frac, max 20m³/min	3250	2.5	250	64	10	6.65	19.95	4.00	40	81	3240
2-Well Simul-Frac, max 28m³/min	3250	2.5	250	64	10	10.5	21	5.84	58.39	56	3270
3-Well Simul-Frac, max 28m³/min,	3250	2.5	250	64	10	9	27	5.64	56.38	58	3270
3-Well Simul-Frac, max 28m³/min, 3WL	3250	2.5	250	64	10	9	27	5.64	56.38	58	3270

Table 15—Summary of key design inputs for all scenarios (Imperial)

Scenario Name	Target Lateral Length (ft)	Sand Loading (lb/ft)	Avg Slurry Concen. (Treatment) Per Stage (lb/gal)	Max Working Pumping Pressure (PSI)	Avg Cluster Spacing (ft)	Max Working Pumping Flow Rate (bbl/min)	Max Working Frac Spread Flow Rate (bbl/min)	Avg Clusters Per Stage	Avg Stage Length (ft)	Avg Number Completed Stages Per Well	Avg Lateral Length Per Well (ft)
Base Single Frac	10,663	1,680	2.09	9,280	32.8	75.5	151	6.17	202	53	10,728
2-Well Simul-Frac, max 20m³/min	10,663	1,680	2.09	9,280	32.8	56.6	113.2	5.64	185	58	10,728
3-Well Simul-Frac, max 20m³/min	10,663	1,680	2.09	9,280	32.8	41.8	83.6	4.00	131	81	10,630
2-Well Simul-Frac, max 28m³/min	10,663	1,680	2.09	9,280	32.8	66	132	5.84	192	56	10,728
3-Well Simul-Frac, max 28m³/min,	10,663	1,680	2.09	9,280	32.8	56.6	113.2	5.64	185	58	10,728
3-Well Simul-Frac, max 28m³/min, 3WL	10,663	1,680	2.09	9,280	32.8	56.6	113.2	5.64	185	58	10,728

Some key, high-level simulation operational results are displayed in Table 16 (Metric) and Table 17 (Imperial).

Table 16—Summary of key operational outputs for all scenarios (Metric)

Scenario Name	Avg Frac Water Per Unit Length (m³/m)	Avg Stage Pumping Pressure (Treatment) (MPa)	Avg Stage Pumping Flowrate (Treatment) (m³/min)	Peak Output Hydraulic Power (HP)	# Frac Engines & Pumps	Equiv. Pumping Time Per Unit Length (min/m)	Avg. Time Between Frac (min)	Avg Lat Length Per Day (Frac Phase) (m/day)	Avg Lat Length Per Day (All Phase) (m/day)
Base Single Frac	11.68	63.6	10.12	17,100	14	1.32	12.9	937	319
2-Well Simul-Frac, max 20m³/min	11.82	59.53	8.76	25,629	21	0.77	18.5	1,496	363
3-Well Simul-Frac, max 20m³/min	12.53	50.14	6.65	24,799	20	0.72	32.5	1,441	346
2-Well Simul-Frac, max 28m³/min	11.77	62.96	9.32	29,596	24	0.72	16.0	1,668	373
3-Well Simul-Frac, max 28m³/min,	11.82	59.53	8.76	38,443	31	0.51	34.4	1,988	386
3-Well Simul-Frac, max 28m³/min, 3WL	11.82	59.53	8.76	38,443	31	0.51	19.4	2,278	396

Table 17—Summary of key operational outputs for all scenarios (Imperial)

Scenario Name	Avg Frac Water Per Unit Length (bbl/ft)	Avg Stage Pumping Pressure (Treatment) (PSI)	Avg Stage Pumping Flowrate (Treatment) (bbl/min)	Peak Output Hydraulic Power (HP)	# Frac Engines & Pumps	Equiv. Pumping Time Per Unit Length (min/ft)	Avg. Time Between Frac (min)	Avg Lat Length Per Day (Frac Phase) (ft/day)	Avg Lat Length Per Day (All Phase) (ft/day)
Base Single Frac	22.4	9,224	63.6	17,100	14	0.40	12.9	3,075	1,046
2-Well Simul-Frac, max 20m³/min	22.7	8,634	55.1	25,629	21	0.24	18.5	4,907	1,190
3-Well Simul-Frac, max 20m³/min	24.0	7,272	41.8	24,799	20	0.22	32.5	4,728	1,134
2-Well Simul-Frac, max 28m³/min	22.6	9,131	58.6	29,596	24	0.22	16.0	5,471	1,224
3-Well Simul-Frac, max 28m³/min,	22.7	8,634	55.1	38,443	31	0.16	34.4	6,522	1,266
3-Well Simul-Frac, max 28m³/min, 3WL	22.7	8,634	55.1	38,443	31	0.16	19.4	7,475	1,298

The number of engines and pumps are scaling approximately linearly with peak frac spread flow rate. Scenario 5 sees its swap times (time between frac) go up even more than Scenario 3 due to higher per-well flow rates reducing pumping times. The 3rd wireline in Scenario 6 greatly mitigates that.

Scenarios 4-6 offer significant cycle time and cost savings over the Base Single Frac scenario. **All-Phase (Prep-to-Demob) costs are reduced by approximately 5-7%, and lateral length completed per day is increased by 17-24%** Fig. 35 shows the relative difference between each scenario and the Base Single-Frac scenario (Scenario 1). **Frac Phase costs are reduced by approximately 7-10%, and lateral length completed per Frac Phase day is increased by 80-140%** (Fig. 36).

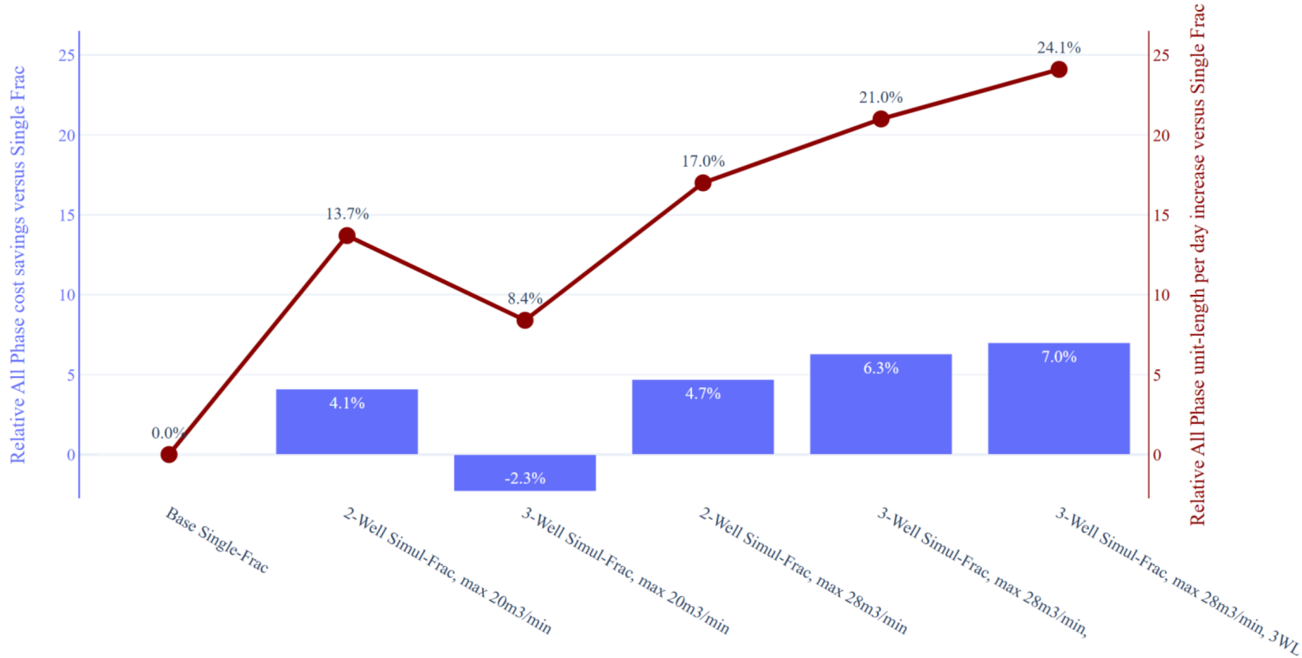

Figure 35—Scenarios' All Phase (Prep-to-Demob) cost savings and increased lateral length per day versus Base Single-Frac scenario

Figure 36—Scenarios' Frac Phase cost savings and increased lateral length per day versus Base Single-Frac scenario

The 2-Well Simul-Frac, max 20m^3/min represents conservative constraints and significant cost and time reductions. Translating these relative savings into hypothetical, absolute terms increases savings transparency. Fig. 37 shows the All Phase (Prep-to-Demob) absolute savings compared to a single-frac scenario with 3,500-m laterals costing $5.8MM/well.

Figure 37—Absolute all-phase, per-well completions cost and cycle time savings over hypothetical 3500-m single-frac completion

For the conservative, 2-Well Simul Frac, 20m^3/min scenario, the **savings would be almost $250,000/well** and almost 1.5 days faster. A 6-well pad could have **six wells online nearly 9 days sooner**.

Even for those whom the max 28m^3/min scenarios are presently infeasible, the **>$350,000/well and approximately 2 days/well benefits** are significant enough to justify a discussion with service providers on how best to eliminate current bottlenecks. This exercise indicates pumping schedules and contracts based on single-frac completion designs should be reviewed with the pumping provider to better align for faster cycle times.

Potential Future Work

The workflow and intuition advanced by this paper could be enhanced in multiple ways.

1. Comparison of frac pumping services contracts that vary in one or more of the following.
    a. Active pumping charge rate ($/hr) also varying on pressure, not just flow rate
    b. Criteria for selecting flow rate and/or pressure for determining active pumping charge rate ($/hr)
        i. Stage with max HP on pad (like this paper assumed)
        ii. Each stage's average flow rate and pressure
        iii. Each stage's average treatment (sand pumped at surface) flow rate and pressure
    c. Varying inactive/standby charges for all non-active pumping times
2. Sensitivity to number of wells per pad and including scenarios for mixing single-, 2-well simul-, and/or 3-well simul-frac
3. Sensitivity to mill-out, cleanout, etc. durations and costs
4. Sensitivity to varied casing designs that will drive different pumping physics and per stage flush volumes
5. Campaign-wide scenarios that incorporate pad and well variability into a wholistic schedule view
6. Repeated study for single-point entry designs which would not have the same tradeoffs as plug-and-perf, limited entry scenarios and could more realistically consider 4-well-and-beyond simul frac.

7. Integrated economics (including drilling, well performance, etc.) to assess impact of completions cost and cycle time on life cycle cashflows (so value of production acceleration is properly considered)

Summary

This paper presented a novel, simulation-driven workflow to quantify the potential economic and efficiency impacts of simultaneously fracturing (i.e., simul-frac'ing) multiple wells. It investigates how design constraints—particularly reduced flow rates per well—interact with completion design parameters such as cluster count per stage. The approach highlights the tradeoff between frac'ing multiple stages simultaneously and increased stage counts per well—enabling operators to optimize designs prior to execution, enhancing efficiency, and minimizing cost-related risks.

After providing an overview of recommended terminology, six scenarios were described and analyzed. Each one underwent a series of optimizations such that all comparisons could be best-versus-best. Scenario 1 was a Single-Frac scenario; it served as the base scenario to which all others were compared. To maximize the value of the relatively high flow rate per well, an optimal number of clusters per stage were added throughout the lateral as rates were predicted to be high enough to meet minimum rate per cluster requirements.

The 2^{nd} and 3^{rd} scenarios were 2-Well Simul-Frac and 3-Well Simul-Frac scenarios constrained by existing operational constraints (single blender and sand per day throughput capacity). The complex web of cascading implications and tradeoffs were highlighted. Of these three, in these specific circumstances, Scenario 2, the 2-Well Simul-Frac scenario, offered the lowest overall completions cycle time and completions cost. The full completions operations cycle time and cost (i.e. Prep-to-Demob cycle time and cost) would be **almost 14% faster** (measured in completed lateral-length per day) **and over 4% cheaper**, respectively, in comparison to the Base Single Frac scenario. Frac Phase cycle time and costs would be almost **60% faster and 7% cheaper.**

The 3-Well Simul-Frac scenario was faster but more expensive than the Base Single-Frac scenario. The benefits of simultaneously frac'ing three stages were outweighed by the cost of the large number of stages needed per well (only being able to sustain 4 clusters per stage). A brief analysis and explanation of the nonlinear impact of clusters per stage was provided.

Scenarios 4 through 6 assumed the only constraint was a maximum frac spread/interval flow rate of $28m^3$/min. Scenario 4 and 5 were 2- and 3-well simul-frac operations with two wireline spreads. To test the value of 3-well simul-frac with no wireline on the critical path, Scenario 6 repeated Scenario 5 but with a 3^{rd} wireline spread. All these scenarios show significant speed increases (17-24% increases in completed lateral length per day) and cost reductions (approximately 5-7%) in comparison to the Base Single Frac scenario's All-Phase metrics. Frac Phase **lateral length per day increased approximately 80-140%,** and Frac Phase **cost reduced by 7-10.5%.** Unlocking this value on a 100-well schedule would add hundreds of well-days and save tens of millions of dollars in a calendar year.

It is essential one understand the example scenario outcomes are highly circumstance dependent. Varying any of the following can drastically affect which scenario most reduces completions cycle time and/or cost.

- frac gradient
- minimum flow rate per cluster
- supply chain constraints
- pumping service provider contract
- fuel type, lateral lengths
- preferred flush volumes

- number of wells per pad

For example, with different contractual frameworks, the 3-Well Simul-Frac breaks even with 2-Well Simul-Frac cost-wise and continues to show cycle time savings. Future work should include sensitivities on such variables as well as a deep-dive on simul-frac utilizing various sleeve technologies—possibly assessing 4-well simul-frac and beyond.

The paper's primary importance is, rather than the specific outcomes, documenting the need for a method of precisely quantifying the numerous tradeoffs given any specific circumstances. This enables engineers, when faced with complex options, to obtain clarity and confidence in a simulated, low-risk environment before committing capital to a given design or operational strategy.

The results of this paper, that simulations of 2- and 3-well simul-frac operational configurations offer multi-six-figure savings per well and Frac Phase and All Phase lateral length per day increases of 60-140% and 15-25%, respectively, are representative of those seen in practice. The study should add evidence to the proposition that hydraulically fracturing wells simultaneously, in general, offers the unconventionals industry significant efficiency gains.

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